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REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY-SUNSET FIELD, SAN JOAQUIN BASIN, CALIFORNIA

Annual Report
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University of Utah
Salt Lake City, Utah

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Reactivation of an Idle Lease to Increase Heavy Oil Recovery through Application of Conventional Steam Drive Technology in a Low Dip Slope and Basin Reservoir in the Midway-Sunset Field, San Joaquin Basin, California

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

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Abstract

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During the fourth year of the oil demonstration project, production from the 8 ac four-pattern steam flood pilot continued to remain high. As of June 1999, the oil rate was averaging 284 BOPD and the cummulative oil production from the pilot alone was 284 MBO. The steam-oil and water-oil ratios, measures of steam flood effectiveness, closed the year at about 5 and 8, respectively. Also, during the year an additional 37 new wells drilled in 1998 surrounding the pilot were put into cyclic production. By the second quarter of 1999 they were producing up to 381 BOPD, bringing the total oil rate for the Pru Fee property up to 658.9 BOPD. The total production from the property since the beginning of the project in late 1995 is 413.7 MBO.

Executive Summary

REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY-SUNSET FIELD, SAN JOAQUIN BASIN, CALIFORNIA

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The 40 acre Pru Fee property is located in the super-giant Midway-Sunset field and produces from the upper Miocene Monarch Sand, part of the Belridge Diatomite Member of the Monterey Formation. The Midway-Sunset field was discovered prior to 1880. The original 13 wells drilled on the property in the early 1900's were operated on primary production by Bankline Oil Company prior to 1959, then Signal Oil Company until 1969, when infill drilling and cyclic steaming was initiated by Tenneco. During the half century of primary production nearly 1.8 MMBO was produced from the Pru property, 114 to 151 MBO per well, but production declined steadily reaching insignificant quantities by the late 1960's. Cyclic steaming was partially successful in extracting the remaining viscous 13° API oil until the Pru property was shut down in 1986 as uneconomic. Total secondary recovery from the 40 acre site peaked at about 300 BOPD in 1972, but by the time the property was shut-in it had dropped to less than 10 BOPD. ARCO Western Energy (AWE) acquired the lease in 1988 along with various producing properties in the Midway-Sunset field. On October 31, 1998 all of the AWE properties in the southern San Joaquin basin, including Pru Fee, were passed through Mobil with simultaneous closing and transfer to Aera Energy LLC, a Shell-Mobil joint-venture company. AWE continued to operate the property on contract to Aera Energy LLC until December 31, 2000, at which time operatorship passed to Aera Energy.

In June 1995, the shut-in Pru Fee property was selected for a DOE Class 3 oil technology demonstration. Initially, this resulted in the renovation of old wells and cyclic production facilities at the site and the drilling of two new wells, Pru 101 and TO-1. Pru 101 was

cored, steam stimulated, then put into production. In January 1997 the demonstration project entered its second and main phase with the purpose of demonstrating on an 8 acre four-pattern pilot whether steamflood can be a more effective mode of production of the heavy, viscous oils from the Monarch Sand reservoir than the more conventional cyclic steaming. The objective is not just effectively to produce oil from the pilot site within the Pru Fee property, but to test which production parameters optimize total oil recovery at economically acceptable rates of production and production costs.

The Monarch Sand is present at depths of 1100-1400 feet at the Pru Fee property. Like other sands bodies within the Monterey Formation, it is a deep submarine channel or proximal fan deposit encased in diatomaceous mudstone. The sand is derived from an elevated portion of the Salinas block, which during the late Miocene lay immediately to the west of the San Andreas fault just 15 miles to the west of the site. The top of the Monarch Sand, actually a Pliocene/Miocene unconformity, dips at less than 10° to the southeast. The unconformity bevels downward at a very low angle to the northwest across the upper portion of the Monarch Sand body. The net pay zone, which averages 220 feet at Pru, thins to the southeast as a top of the sand dips through the nearly horizontal oil-water contact (OWC). The only other oil-bearing unit at the Pru Fee property is the Tulare Formation, interbedded fluvial sands and shales at a depth of about 500 feet which contain an estimated 2.5 MMBO potential reserves. These additional reserves were discovered as a consequence of drilling and logging the wells for this DOE Class 3 demonstration pilot.

Average Monarch Sand reservoir characteristics derived from core and the log model developed for this project are 31% porosity and 2,250 md permeability. The initial (1995) average oil saturation is estimated to be 59%. However, all wells have a relatively thick transition zone of downward decreasing oil saturations in the bottom half of the pay interval. The oil is both heavy and viscous, 13° API and 2200 cp at the reservoir temperature of 100° F.

During the initial phase of the project a multifaceted feasibility study was carried out to examine whether the pilot project could be justified technically and economically at this site. This study included:

1. Recompletion of 9 shut-in wells and drilling of an additional producer and a new temperature observation well. A core was taken from the reservoir interval in the new producer, Pru-101. The wells were produced by conventional cyclic steaming over a period of 15 months to establish a production baseline for the site.

2. Characterization of the stratigraphy and petrophysical properties of the Monarch Sand reservoir using existing well logs and analyses on samples in the core taken from Pru-101. The resulting data were used to develop a geostatistical model of the reservoir at the Pru Fee property and a specific reservoir simulator for the pilot test site on the property.

3. Use of the reservoir simulator to test various steamflood and cyclic steaming production options leading to design of a production strategy for the pilot steamflood

based on a four pattern, 9-spot array covering 8 ac near the center of the 40 ac Pru Fee property. The array chosen required drilling additional producers and injectors to supplement the existing wells recompleted in the initial phase of the project.

Reservoir simulations with geostatistically generated data sets revealed that the initial fluid distribution in the reservoir had the most significant impact on the economics of the cyclic-flooding process. The initial fluid distribution was determined by the placement of the oil-water contact and the resulting transition zone in the reservoir. The current approach involves initial steam injection within the upper third of the oil column, where the oil saturation (So) is greater than 50%, so as to avoid undue loss of heat to water. Initial simulations predicted recovery of 23% of original oil in place (OOIP) over a ten-year project cycle following a conventional steam flood strategy alone. However, the simulations showed that as production proceeds and unrecovered oil drains downward, the injection string can be shifted downward to keep pace with the observed steam chest and the simulated high So interval. After approximately 5 years of production by conventional steam flood through vertical wells, during which time an estimated 16% OOIP will be recovered from the 8 acre pilot, an additional 15% OOIP could be recovered by a pair of appropriately placed horizontal wells.

Activities on the pilot site during the actual steam flood demonstration included drilling 18 new wells - 11 producers (Pru-201 through Pru-211), 4 injectors (Pru 12-1 through Pru 12-4), and three temperature observation wells (TO-2 through TO-4). The drilling was started on January 14 and completed on March 16, 1997. All wells were logged. The four pattern, 9-spot array utilizes 10 pre-existing wells that were recompleted and cyclic steamed in the initial phase of the project. All new wells were drilled into the oil-water contact to establish the depth of that horizon. The producers were completed through the entire pay zone, however, the injectors were completed so as to maintain the critical standoff from the OWC deemed optimal in earlier simulations. On the basis of the new wells, the stratigraphic model for the pilot was reevaluated on using GeoGraphix (GES and Prizm) workstation software and the geostatistical distribution of porosity and permeability rerun using GeoMath's Heresim package. This analysis preceded revision of the thermal simulator for the pilot. History matching of steam injection rates and monthly production to fine tune the simulator will provide the basis for optimization of production practices and parameters for the next several years of the demonstration.

During the initial cyclic baseline test period in 1996, production averaged for the total group of 9 wells about 65 BOPD, ranging from 3 to 10 BOPD/well for the old wells and about 15 BOPD for the new Pru 101 well. Total production during the cyclic baseline testing was 28.7 MBO. As soon as the group of new producers had been primed by steaming and in turn put into production in the early summer 1997, rates for the pilot climbed to nearly 400 BOPD. The sharp increase in production can, in part, be attributed to the increase in the number of producers from 9 to 20 and the fact that the performance of the new wells is consistently better than the old renovated wells. However, the well average jumped from about 8 BOPD to nearly 20 BOPD with the onset of the pilot steam flood. As of June 1999, the oil rate at the Pru pilot was averaging 284 BOPD. To date the cumulative production of the Pru pilot is 284 MBO. Temperature monitoring at the site is suggesting that full steam flood production had begun late in 1997. Nevertheless, the entire volume of the steam flood pilot had not reached the maximum temperature as of mid-June 1999.

The early production success of the pilot and the discovery of significant quantities of oil in the Tulare Formation during the preparation of the steam flood pilot lead AWE early in 1998 to expand operations elsewhere in the Pru Fee property. Thirty-seven cyclic producers in the Monarch Sand surrounding the steam flood pilot put into production in 1998 and early 1999 reached oil rates during the second quarter of 1999 in the range 363 to 381 BOPD. In just a year, they have already produced an additional 129.7 MBO. This number does not count the additional oil produced from the 19 new cyclic wells in the Tulare Formation that came on stream in 1998.

It is highly likely that without the incentives to AWE to partner with the DOE Class Program in carrying out this pilot project, the Pru Fee property never would have been brought back into production. Based on historic performance and the existing geologic evaluation, it was known to be a highly marginal property. Yet in the four years since the initiation of the DOE Class 3 demonstration the total production from this 40 acre shut-in tract has gone from zero to 658.9 BOPD. In addition, AWE has invested (without a DOE matching contribution) in a total of 54 new cyclic producers external to the steam flood pilot. Total production from the Pre Fee property since the end of 1995 is 413.7 MBO.

Acknowledgements

The project team members wish to acknowledge the helpful advice of Gary D. Walker and Viola Rawn-Schatzinger of the DOE National Petroleum Technology Office on both administrative and technical issues related to the project.

The project has depended on access to several critical software products, which have been provided to the prime contractor under academic licences for use at the University of Utah. We are grateful to the companies for their contributions to the project:

GeoGraphix: *GES* and *Prizm* workstation modules

GeoMath: *Heresim* geostatistical modeling tools

Computer Modeling Group Ltd.: *STARS* thermal reservoir simulator

Chapter 1

Introduction

General Statement

A previously idle portion of the Midway-Sunset field, Aera Energy's Pru Fee property, has been brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. This property, shut-in over a decade ago as economically marginal using conventional cyclic steaming methods, has a 200-300 foot thick oil column in the Monarch Sand. However, the sand lacks effective steam barriers and has a thick water-saturation zone above the oil-water contact. These factors require an innovative approach to steam flood production design that will balance optimal total oil production against economically viable steam-oil ratios and production rates. The methods used in this DOE Class III oil technology demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize properties with declining production of heavy oils throughout the region.

The Midway-Sunset field is the site of the largest thermal enhanced oil recovery operation in the United States. Cyclic, steam flood, hot-water and in situ combustion (fire-flood) technologies are utilized on an ongoing basis within various parts of the field. Indeed, thermal enhanced recovery methods, now standard in all portions of the field since the early 1960's, are responsible for pulling the field out of a steady decline in production. As a consequence of intensive application of thermal enhanced recovery methods, production rates increased four-fold and currently stand at 155.1 MBOPD, making Midway-Sunset the third largest oil field in North America in terms of daily production. The scale of the operation is impressive. Over 10,000 wells are producing from an area 21,830 ac in size. Cummulative production from the field exceeds 2,300 MMBO and 563 BCF of gas; estimated remaining recoverable reserves are in excess of 450 MMBO. A major goal of this project is to further increase production and extend the life of the field by encouraging investment in portions of the field previously considered economically marginal for geologic or operational reasons.

The 40 acre Pru Fee property is located near the center of the super-giant Midway-Sunset field (Fig. 1-1) and produces from the upper Miocene Monarch Sand, part of the Belridge Diatomite Member of the Monterey Formation. The Midway-Sunset field was discovered prior to 1880. The original 13 wells drilled on the property in the early 1900's were operated on primary production by Bankline Oil Company prior to 1959, then Signal Oil Company until 1969, when infill drilling and cyclic steaming was initiated by Tenneco. During the half century of primary production nearly 1.8 MMBO was produced from the Pru property, 114 to 151 MBO per well, but production declined steadily reaching insignificant quantities by the late 1960's. Cyclic steaming was partially successful in extracting the remaining viscous 13° API oil until the Pru property was shut down in 1986 as uneconomic. Total secondary recovery from the 40 acre site peaked at about 300 BOPD in 1972, but by the time the property was shut-in it had dropped to less than 10 BOPD. ARCO Western Energy (AWE) acquired the lease in 1988 along with various producing properties in the Midway-Sunset field. On October 31, 1998 all of the AWE properties in the southern San Joaquin basin, including Pru Fee, were passed through Mobil with simultaneous closing and transfer to Aera Energy LLC, a Shell-Mobil joint-venture company. AWE continued to operate the property on contract to Aera Energy LLC until December 31, 2000, at which time operatorship passed to Aera Energy.

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By the end of June 1999, the cummulative oil production (Fig. 1-2) from the 8 ac four-pattern steam flood pilot had reached 284 MBO, and increase of 108 MBO over the past year. The cummulative oil production from 37 additional cyclic wells drilled in 1998 had reached 129.7 MBO, which is 111.2 MBO from the new wells in just the last 12-month period. This brings the total cummulative oil production from the Pru Fee property by mid-year to 413.7 MBO.

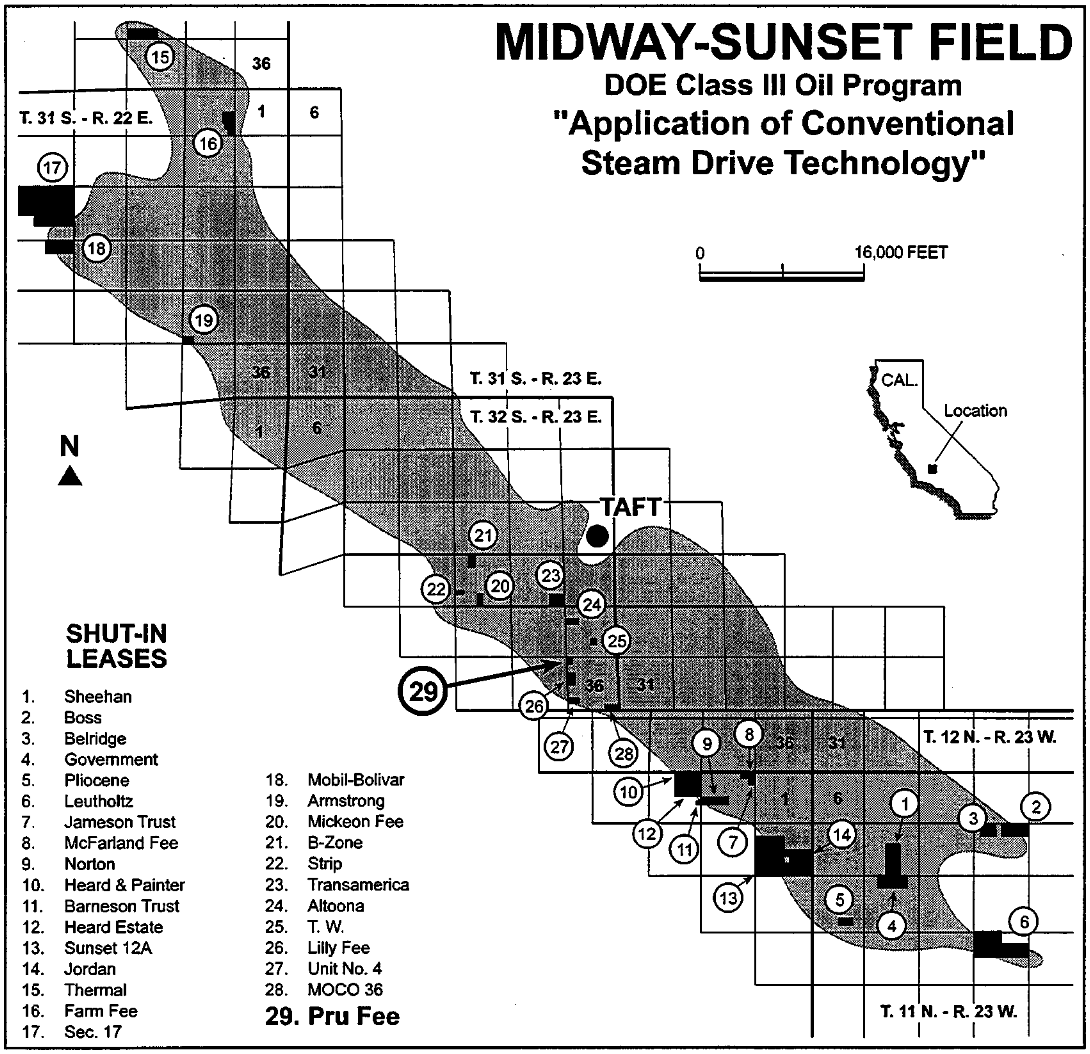

Figure 1-1: Index map of the Midway-Sunset field showing location of the Pru Fee property and other leases shut-in at the start of the project.

Project Activities in Year 4

During the fourth year of the project the steam flood pilot continued to maintain a good rate of production as the temperature in the reservoir continued to build, ARCO Western Energy (AWE) completed the programmed drilling of 37 additional producers in the Pru Fee property and brought the wells into cyclic production, and the property changed ownership and operatorship.

In the second half of 1998, ARCO Western Energy, including all of its California holdings, was transferred to Aera Energy LLC, a Shell-Mobil joint venture company. The formal transfer of properties from ARCO to Aera Energy LLC took place at the end

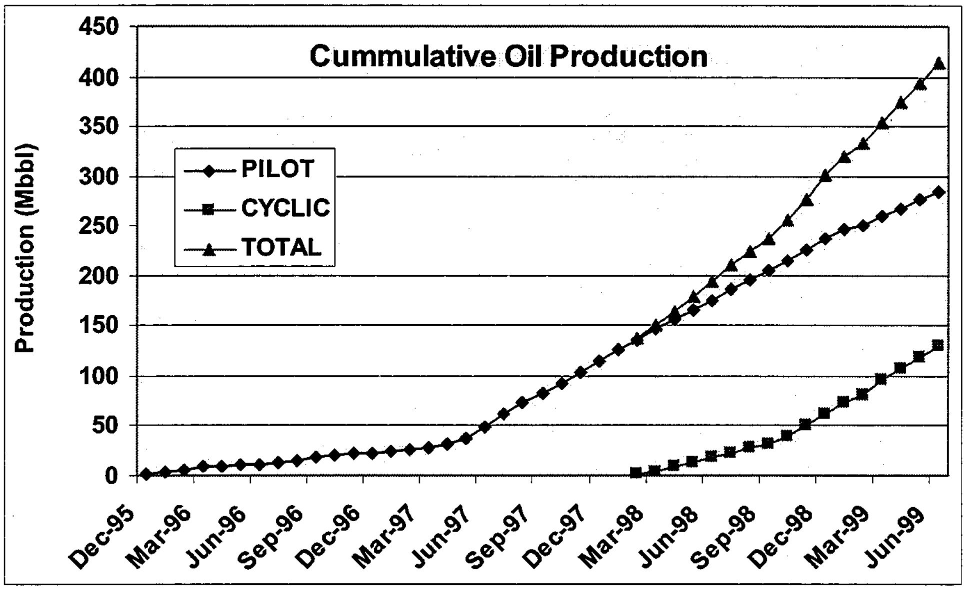

Figure 1-2: Cummulative oil production from the Pru Fee property since the start of the DOE oil technology demonstration in late 1995. The steam flood pilot was initiated in mid-1997 and the "300-series" cyclic wells were put online early in 1998.

of October 1998, but AWE staff continued to operate the former ARCO properties in the Midway-Sunset field through December 31, 1998. At the present time the University of Utah, the prime contractor for the Pru steam flood demonstration, is negotiating with Aera Energy to have Aera continue to operate the steam flood demonstration on Pru property. No problems are anticipated with continuing the project as originally planned. Indeed, under the operatorship of Aera Energy, this oil demonstration project is scheduled to expand its scope of work and technical contributions.

The DOE National Office of Petroleum Technology has approved a one-year no-cost extension of the project to allow a side-by-side comparison of cyclic and steam flood thermal recovery methods to be conducted on the Pru Fee property. The steam flood is currently underway near the center of the 40 ac site. The cyclic demonstration will use at least a majority of the 37 wells drilled by AWE in 1998 outside of the steam flood pilot. These wells have been completed and all now are being operated in cyclic mode.

At no additional cost to the DOE or to the operator, this expansion of the scope of the oil technology demonstration will add immeasurably to the ultimate value of the project. The project is now scheduled to end on March 13, 2001.

The principal activities during the year included:

- Steam flood in 8 ac pilot and continued production surveillance,
- Completion of group of 37 additional wells in the Monarch Sand Reservoir, initiation of cyclic production, and surveillance,

- Transfer of ownership and operating responsibility from ARCO Western Energy to Aera Energy LLC,
- Investigation of the early production history of the Pru Fee property,
- Comparison of actual production in the steam flood pilot with the predictions from the initial reservoir simulator.

Project Organization

This Class III Oil Technology Demonstration, which is sponsored with matching funds from the U.S. Department of Energy, Office of Fossil Energy, involved during its fourth year the collaboration of four separate organizations:

- the *University of Utah*, serving as the Prime Contractor and project coordinator
- *ARCO Western Energy*, the owner and operator of the Pru Fee property at the beginning of the project
- *Aera Energy LLC*, the owner and operator of the Pru Fee property after the end of 1998
- the *Utah Geological Survey*, responsible for technology transfer and aspects of the geologic evaluation.

The project team members during the past year and their particular areas of responsibility to the project are:

College of Engineering, University of Utah (Salt Lake City, UT)
- Steven Schamel - project manager and research coordinator
- Milind Deo - reservoir characterization and simulation
- Craig Forster - reservoir characterization and geostatistics

Aera Energy LLC (Bakersfield, CA)
- Grahem Buksh – reservoir management engineer
- K.M. (Mike) Deets – reservoir management engineer
- Lucy S. Bultmann – reservoir management geologist

ARCO Western Energy (Bakersfield, CA)
- Kevin Olsen- petroleum engineering and site management
- Mike Simmons - petroleum geology and reservoir characterization

Utah Geological Survey (Salt Lake City, UT)
- Doug Sprinkel - stratigraphic analysis and reservoir characterization
- Roger Bon - technology transfer

ARCO Exploration and Production Technology (Plano, TX)
- Creties Jenkins - advisor for stratigraphy and reservoir characterization

Chapter 2

History of Primary Production on the Pru Fee Property

The Midway-Sunset field was discovered prior to 1880. The original 13 wells drilled on the Pru Fee property in the early 1900's were operated on primary production by Bankline Oil Company prior to 1959, then Signal Oil Company until 1969, when infill drilling and cyclic steaming was initiated by Tenneco. During the half century of primary production nearly 1.8 MMBO was produced from the Pru Fee property, 114 to 151 MBO per well, but production declined steadily reaching insignificant quantities by the late 1960's. Cyclic steaming was partially successful in extracting the remaining viscous 13° API oil until the Pru property was shut down in 1986 as uneconomic. Total secondary recovery from the 40 acre site peaked at about 300 BOPD in 1972, but by the time the property was shut-in it had dropped to less than 10 BOPD. ARCO Western Energy (AWE) acquired the lease in 1988 along with various producing properties in the Midway-Sunset field. On October 31, 1998 all of the AWE properties in the southern San Joaquin basin, including Pru property, were passed through Mobil with simultaneous closing and transfer to Aera Energy, a Mobil-Shell joint-venture company.

The early history of production at Pru (Fig. 2-1) was researched by Kevin Olsen using the ARCO Western Energy files. The 13 wells produced by the Bankline Oil Company were distributed rather uniformly across the entire 40 ac Pru property. Just four wells - #6, #7, #10, and #11 – were located within the area of the current steam flood pilot. Although the net pay within the Monarch Sand reservoir is greatest in the northwest corner of the property and decreases to the southeast, there is no clear correlation between net pay and the cumulative production per well. The oil-water contact rises stratigraphically eastward across the property. Accordingly, the wells on the eastern side of the property show higher cumulative water production. The cumulative well production (Fig. 2-2) for the period 1914-1970 is presented in Table 2-1.

Production was entirely primary with a solution gas drive. As a consequence, the total production rate declined gradually during the century, finally in 1970 reaching less than 10 BOPD (Figure 2-1). During the later part of the primary production the rates of water production began to rise, in some wells nearly equaling the rates of oil production. However, this was only in the last decades of primary production.

The cumulative oil production (Figure 2-2) reached 1,789,918 bbls just prior to the wells being shut in. The average total primary production per well was 137,686 bbls and the range was 114,235 to 151,110 bbls.

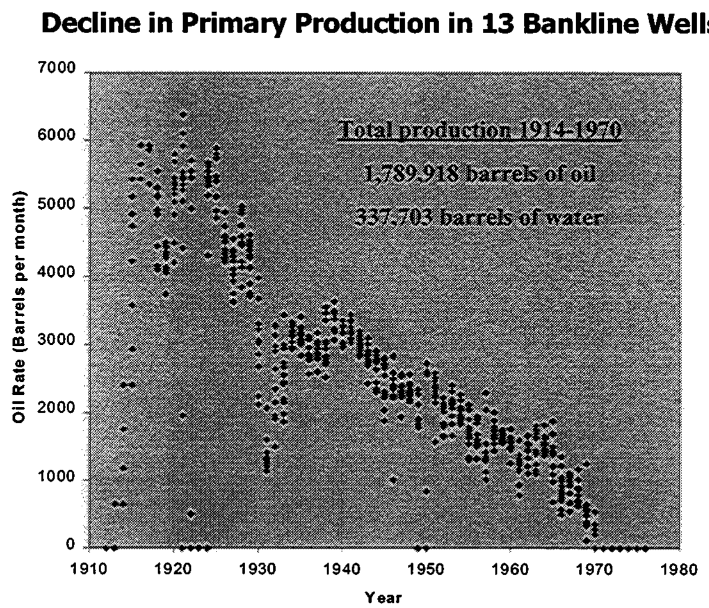

Figure 2-1: Primary production decline in the 13 Bankline wells on the Pru property.

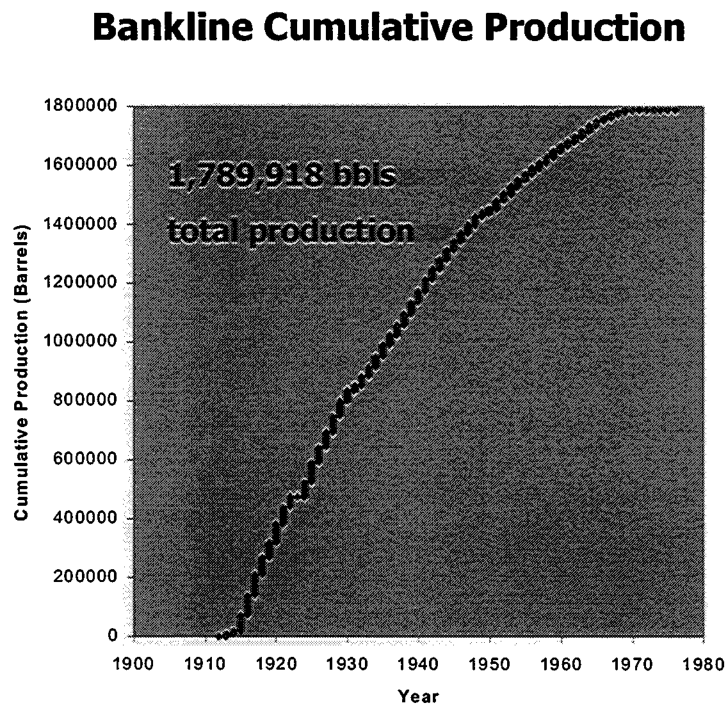

Figure 2-2: Cumulative oil production from the 13 Bankline Oil Company wells.

Table 2-1: Cumulative Production in the Bankline Oil Company wells during the period 1914 through 1970.

PRU WELL	CUMULATIVE OIL, BBLS	CUMULATIVE WATER, BBLS
1	146539	12657
1-A	114235	9290
2	136181	17047
3	143807	42222
4	142517	57706
5	151110	45331
6	144092	22406
7	126683	11410
8	157334	8123
8-A	129123	7405
9	127624	9909
10	145487	18960
11	125186	75237
TOTALS	1789918	337703
AVERAGES	137686	25977

Chapter 3

Continuing Production of the Steam Flood Pilot

Heating the Monarch Sand Reservoir

During the first two years of operation of the steam flood pilot, the four temperature observation wells were logged on a regular basis to track the buildup of heat within the Monarch Sand reservoir. During the period of transfer of ownership between ARCO Western Energy and Aera Energy LLC, this activity was suspended. Thus, a gap in temperature logging existed between September 10, 1998 and June 15, 1999.

The progressive buildup of heat in the four temperature observation wells since the onset of the steam flood operation in the Spring of 1997 can be seen in Figures 3-1 through 3-4. These plots show temperature peaks within two separate stratigraphic intervals. The higher peak (450-650 ft depth) is in the sands of the Pleistocene Tulare Formation, whereas the lower peak (1,100-1,250 ft depth) is in the upper Miocene Monarch Sand reservoir. For reference the plots show the depths down hole of the top of the Monarch Sand and the oil-water contact (OWC), the base of the pay interval. It is important to note that during the entire period of temperature record, the points of steam injection had not been altered. Each injector well is a solid pipe perforated at six points about 10 ft apart and with a standoff from the OWC well in excess of 100 ft. Also it should be noted that the ambient reservoir temperature prior to steam injection was close to 100° F.

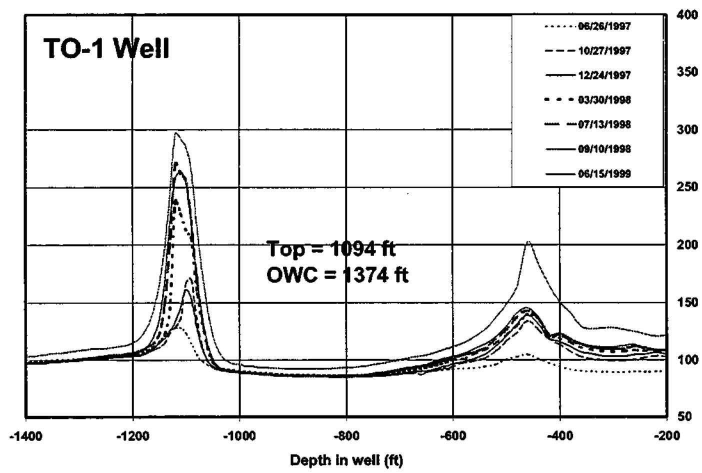

Figure 3-1: Stacked temperature logs for the Pru TO-1 well, which is 100 ft from the nearest injector well.

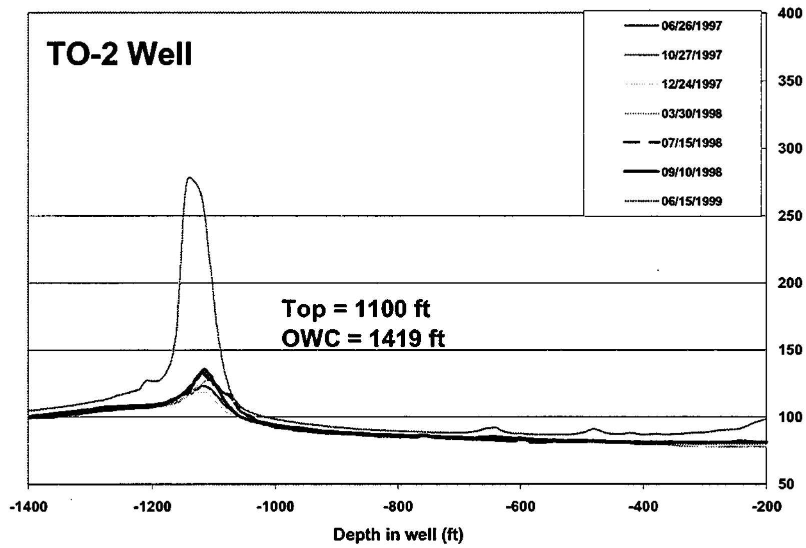

Figure 3-2: Stacked temperature logs for the Pru TO-2 well, which is 90 ft from the nearest injector well.

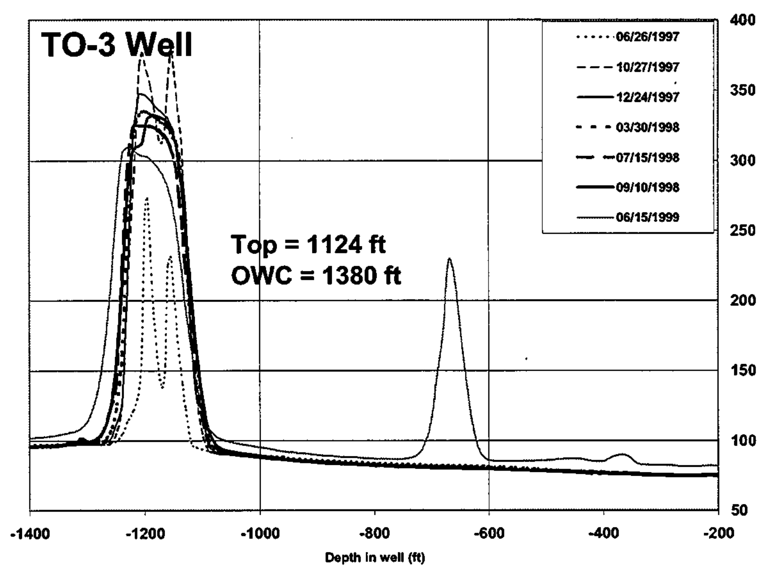

Figure 3-3: Stacked temperature logs for the Pru TO-3 well, which is 45 ft from the nearest injector well.

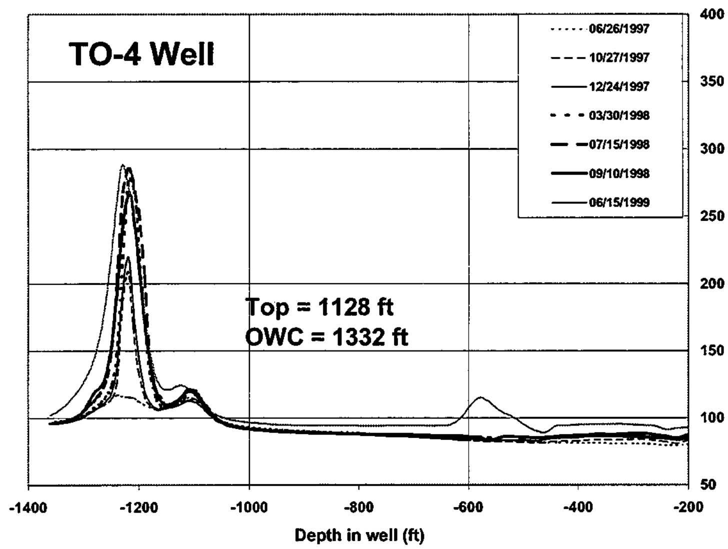

Figure 3-4: Stacked temperature logs for the Pru TO-4 well, which is 110 ft from the nearest injector well.

Table 3-3 provides information about the distances of the temperature observation well from the nearest injector, the depth in the well to the top of the Monarch Sand reservoir and the OWC, and the depths, relative to the top of the reservoir and OWC, to the top and bottom of the injection interval in the nearest injector. It should be clear that the initial thermal response to steam injection recorded in each temperature observation well should be proportional to its proximity to an injector, and for the most part it is so. However, the pattern of reservoir heating implicit in the temperature logs varies greatly between the wells.

The strategy for optimizing steam flood production in the pilot is to put the heat into the upper part of the Monarch Sand reservoir where the oil saturations are observed to be highest (greater than 50-60%), and avoid heating the lower half of the pay interval where water saturations generally exceed 50%. The temperature observation logs provide critical data for knowing if the reservoir heating objectives are being reached.

The major features in each set of temperature observation well logs are described below:

TO-1 well: From the onset of steaming the adjacent I2-1 injector has been losing steam, probably up the outside of the casing, to the shallow Tulare sands at about 500 ft depth. Otherwise, the temperature logs record a very regular heating of the Monarch Sand reservoir and a relatively tight zone of heating within the target 100 ft interval. The maximum temperature recorded is nearly 300° F.

Table 3-1: Information related to Temperature Observation Wells

	TO-1 well	TO-2 well	TO-3 well	TO-4 well
Quadrant in pilot array	NW	NE	SW	SE
Distance from injector	100 ft	90 ft	45 ft	110 ft
Depth top reservoir	-1094 ft	-1100 ft	-1124 ft	-1128 ft
Depth of OWC	-1374 ft	-1419 ft	-1380 ft	-1332 ft
Nearest injector				
Depth - top perforation	47 ft	39 ft	47 ft	44 ft
Depth – base perforation	103 ft	86 ft	107 ft	100 ft
Offset base from OWC	202 ft	187 ft	161 ft	131 ft

TO-2 well: Inexplicably, this well in the northeast quadrant only 90 ft from the nearest injector, shows very sluggish build up of heat in the Monarch Sand reservoir. In the nearly two years of steam injection prior to September 1998, the maximum temperature had risen only about 30° and was virtually static. However, in the last 9 months of record, the maximum temperature jumped about 150° F to stand at 280° F, which is virtually the same as the other temperature observation wells.

TO-3 well: This well, which is only 45 ft away from its nearest injector, has shown a bizarre history of reservoir heating. Whereas all of the other temperature records indicate progressive heating of the reservoir with time, this well reached its maximum temperature of about 380° F in October 1997, only 5 months after steam injection began, and since then has cooled back to 310° F. The interval of elevated temperature is nearly 200 ft thick, twice that in the other temperature observation wells.

TO-4 well: This well in the southeast quadrant is the most distant, 110 ft, from its nearest injector. The history of reservoir heating evidenced by the temperature logs is one of gradual heating, which stabilized around 280° F in mid-1998 and virtually unchanged since then. The zone of heating is close to the target 100 ft thick interval near the top of the Monarch Sand reservoir.

It is interesting to observe that through time the temperature peaks for most of the wells tend to shift downward, which is just opposite of the anticipated rise in heat upward through the reservoir as additional steam is injected. It is not known why this is happening, as it is counter-intuitive.

Another way of examining the temperature observation logs that in most respects is more relevant to the question of whether the entire target interval is being heated is presented in Figures 3-5 through 3-7. These graphs show through time the average temperature recorded in the upper 50 ft, 100 ft and 150 ft interval of the Monarch Sand reservoir. The goal is to put heat into just the upper 100 ft of the reservoir. The graphs show the timing and magnitude of heating of this target interval.

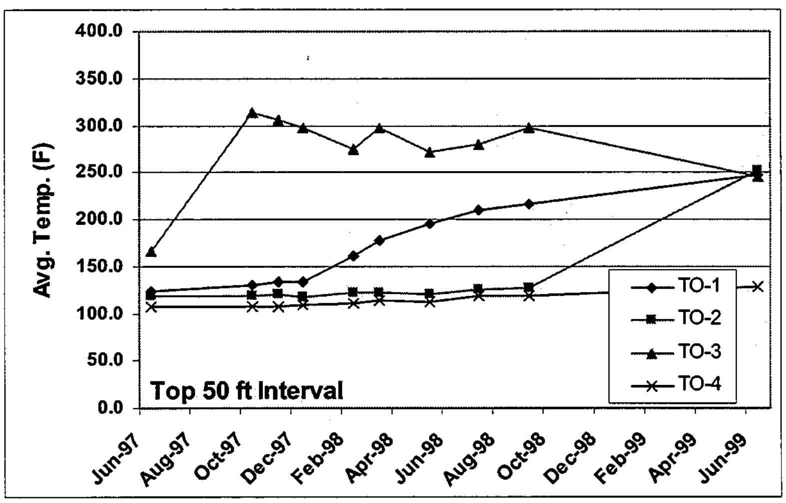

Figure 3-5: Average temperature reached in the upper 50 ft interval of the Monarch Sand reservoir as a function of time. Note convergence to 250° F in three of the wells.

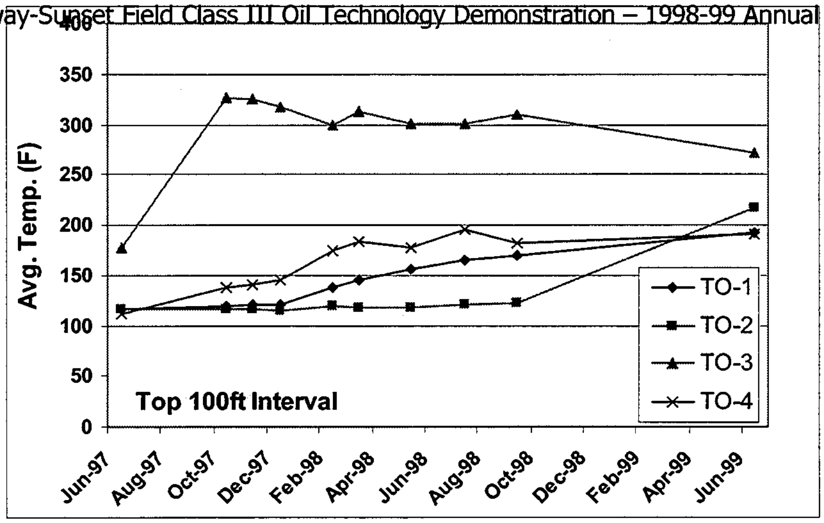

Figure 3-6: Average temperature reached in the upper 100 ft interval of the Monarch Sand reservoir. Note that the June 1999 values range between 190° and 275° F.

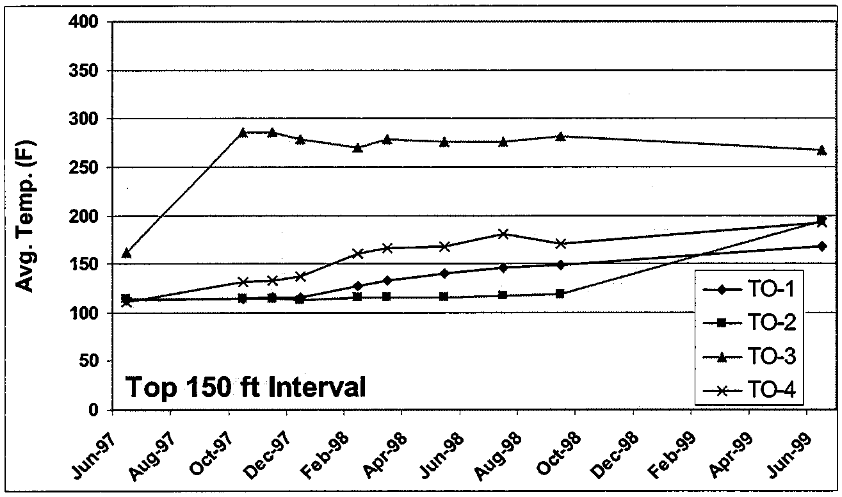

Figure 3-7: Average temperature reached in the upper 150 ft interval of the Monarch Sand reservoir. Note that the June 1999 values range between 160° and 260° F.

The temperature observation wells record two separate aspects of the build up of heat within the Monarch Sand reservoir: (1) variations as a function of distance outward from the injector and (2) spatial variations in the capacity of the reservoir to transmit steam and advective heat. In terms of heating at the site of the temperature observation wells, the wells fall into two groups. The well TO-3 just 45 ft away from an injector reaches maximum average temperature quickly in all interval thicknesses (Figs. 3-5 through 3-7) and either cools slightly or maintains the highest average temperatures. For the wells 90, 100 and 110 ft from the nearest injector, the average temperatures build rather slowly. There is no strict correspondence between distance from the nearest injector and rate of temperature build up.

In as much as the normal distance between injector and producer is in the range 150 to 200 ft, it would be reasonable to conclude that as of the time of the last temperature logging in June 1999 the "steam chest" for the steam flood pilot was not yet fully developed. This slow building of the region of elevated temperature is very likely inhibiting the production potential of the steam flood pilot.

An additional method for monitoring the ambient temperature of the Monarch Sand reservoir is to track the temperature of produced fluids. These temperatures through the life of the entire project are plotted in Figure 3-8.

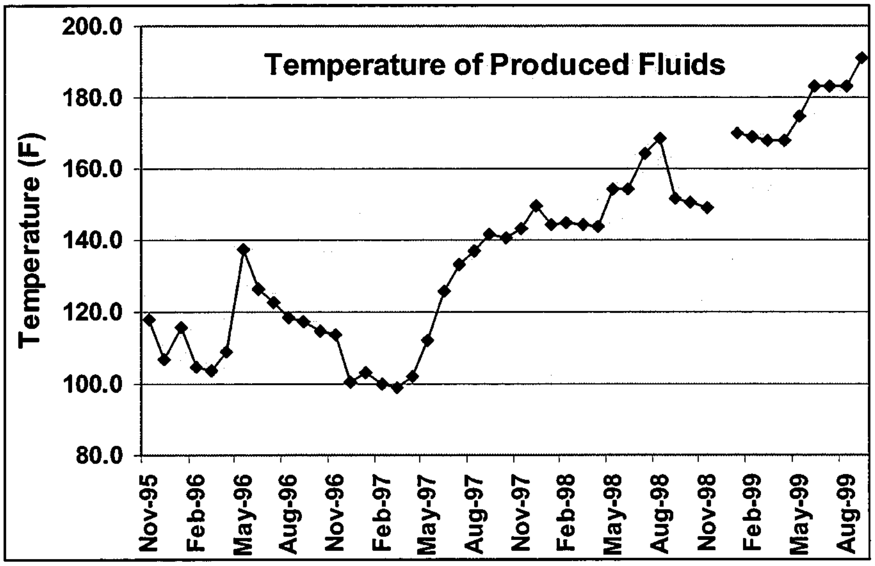

Figure 3-8: Temperature of produced fluids (water and oil) from the four-pattern steam flood pilot showing the gradual increase in reservoir temperature since the onset of the steam flood operation in the second quarter of 1997. The break in December 1998 is related to the change of operator and installation of a different metering line.

The first temperature spike in produced fluids in the four-pattern steam flood pilot relates to cyclic production of a group of renovated wells serving as a general baseline for subsequent steam flood production. Once the entire steam flood array came on line in Spring 1997, there has been a steady increase in the temperature of produced fluids. The temporary plateaus relate to times when steam injection rates were dropped back to a baselevel 1200-1300 BSPD rate. The surge in temperature observed in the past two quarters relates to the considerably higher steam injection rates (up to 2,285 BSPD) being used in the pilot with the intention of driving up the reservoir temperature faster.

Production in Pru Steam Flood Demonstration

The production rates of fluids (Table 3-2) from the 8 ac four-pattern steam flood pilot is shown in Figure 3-9. During the initial phase of evaluation of the pilot from late 1995 through early 1997, oil rates from mainly renovated cyclic wells averaged 65 BOPD. Soon after the steam flood pilot began in February-March 1997, oil rates rose dramatically reaching a maximum of 424 BOPD in July 1997. Since then, the oil rates have fallen back sightly to maintain a general range of 300 to 370 BOPD through the latter half of 1997 and all of 1998. However, production rates fell below 300 BOPD at the time of transfer of operatorship and for the first half of 1999 was in the general range 270 to 280 BOPD. The drop in production rates is a consequence of infrastructure improvements to the site undertaken by Aera Energy LLC. The new construction brought additional steam to Pru from the adjacent Kendon property so as to cycle the new "300-series" wells more rapidly and bring up reservoir temperature in the Monarch Sand across the entire property more quickly. In the second quarter of 1999, the oil rates were again rising to the average of 284 BOPD in June. During the entire period of steam flood, the rates of water production have been rising (Fig. 3-9). Rates of steam injection have been relatively constant between 1,000 and 1,200 BSPD. However, from time to time sluggish producers have been stimulated with steam, which has resulted in periodic spikes in the total steam rate (Fig. 3-9).

By the end of June 1999, the cummulative oil production from the 8 ac steam flood pilot alone stood at 284 MBO.

The steam flood performance factors, the steam-oil (SOR) and water-oil (WOR) ratios, have been quite good (Fig. 3-10). Over the slightly less than two and a half year life of the pilot demonstration the "baseline" SOR has risen slightly from about three to just under five. Only during times of cyclic stimulation of the producers did the SOR ratio increase. During the same period, the WOR has risen from just under five, a very favorable value, to about eight, a very acceptable value.

Table 3-2: Average daily and cummulative production - Pru steam flood pilot
July 1998-June 1999

Month	BOPD bbls	BWPD bbls	BSPD bbls	CumOil Mbbls	CumWater Mbbls	CumSteam Mbbls
July	354.5	1,818.8	1,301.5	187	869	983
August	307.6	1,750.8	1,365.3	196	912	1,037
September	290.4	1,923.5	1,069.3	205	944	1,095
October	324	1,929	1,253	215	983	1,155
November	363	2,138	1,273	226	1,021	1,219
December	372.4	2,412	1,137	238	1,056	1,294
January	285.1	2,330	1,075	246	1,089	1,366
February	184.9	1,368	1,160	251	1,122	1,404
March	167.0	1,309	1,542	259	1,170	1,445
April	270	1,514	1,724	267	1,490	1,221
May	284	2,468	1,422	276	1,567	1,265
June	284	2,433	1,184	284	1,640	1,301

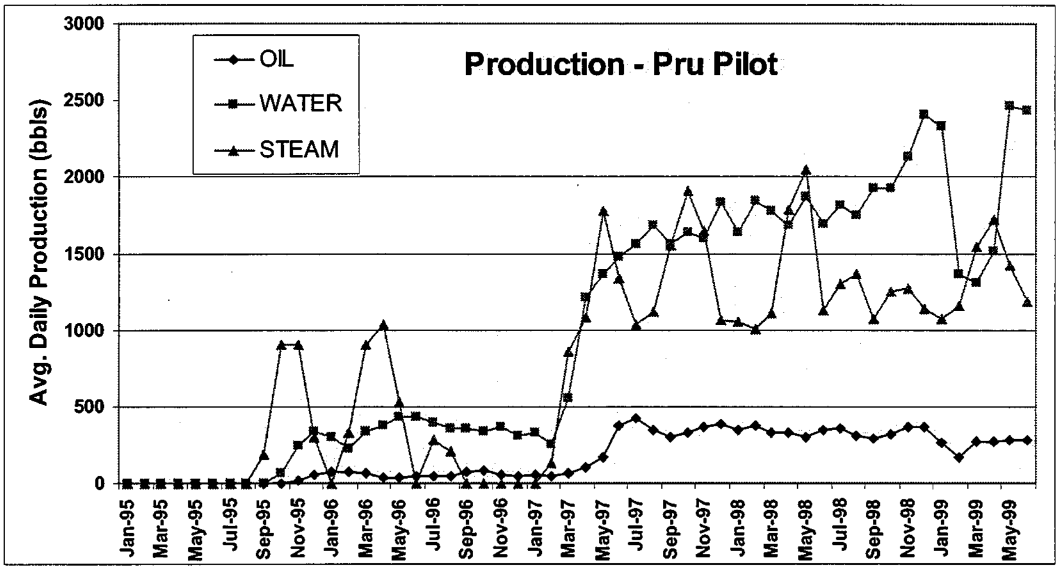

Figure 3-9: Fluids production from the 8 ac four-pattern steam flood pilot through the life of the DOE oil technology demonstration.

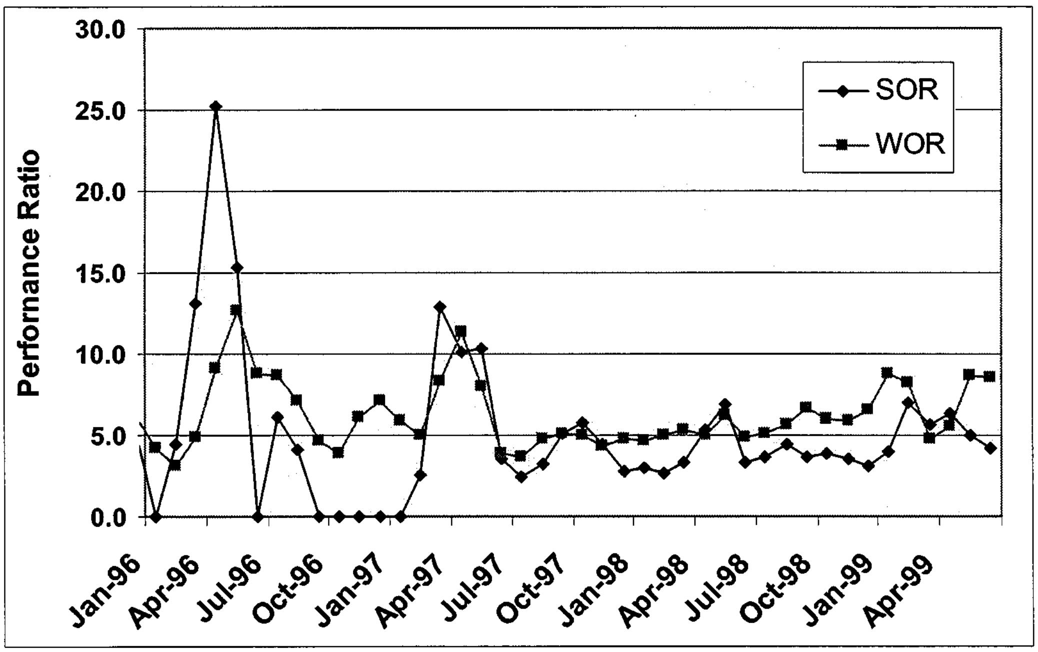

Figure 3-10: Production performance factors for the 8 ac steam flood pilot.

Chapter 4

Expansion of Production on the Pru Fee Property

Drilling of Additional Production Wells

The early production success of the Pru steam flood pilot and the discovery of significant quantities of heavy oil in the Pleistocene Tulare Formation during the preparation of the pilot lead ARCO Western Energy (AWE) early in 1998 to expand operation elsewhere in the Pru Fee property. The wells drilled into the upper Miocene Monarch Sandstone reservoir during 1998 are part of the "Pru 300-series". Six wells were spudded during the period January 5-21 (Pru 301 through Pru 306). In the period May 7-24 an additional six wells were drilled (Pru 307 through 312). Twenty-five wells were spudded in an intensive drilling campaign from August 28 to October 21 (Pru 320 through Pru 350). The additional 37 wells ring the original steam flood pilot on the north, west and southwest (Fig. 4-1). Only the southeast quadrant of the property was not infill drilled; this is an area where the pay interval in the Monarch Sandstone is only about 100 ft thick. The total depth of the "300-series" wells ranges from 1,318 to 1,472 ft (Table 4-1). Twelve of the wells were logged. All of the wells were completed as producers to be cyclic steamed.

In addition to the 37 new wells drilled into the Monarch Sandstone, 20 wells were drilled into the heavy oil saturated intervals in the shallower Tulare Formation. These wells are designated "TPxxx". For the most part the wells are clustered in the southwest quadrant of the Pru Fee property, overlapping only the southern edge of the steam flood pilot. Three of the wells, however, are in the southernmost part of the southeast quadrant. The wells have a total depth of about 700 ft and were all completed as cyclic producers. None of the Tulare oil produced from these wells is commingled with oil produced from the Monarch Sandstone reservoir.

The total of 37 new wells drilled by AWE on the Pru Fee property in 1998 represented a substantial investment in enhanced production. Already by mid-year 1999, this investment was having a remarkable payback.

Figure 4-2 shows the placement of the "300-series" wells in cyclic production. They generally are north, west and south of the four-pattern steam flood pilot located near the center of the Pru Fee property.

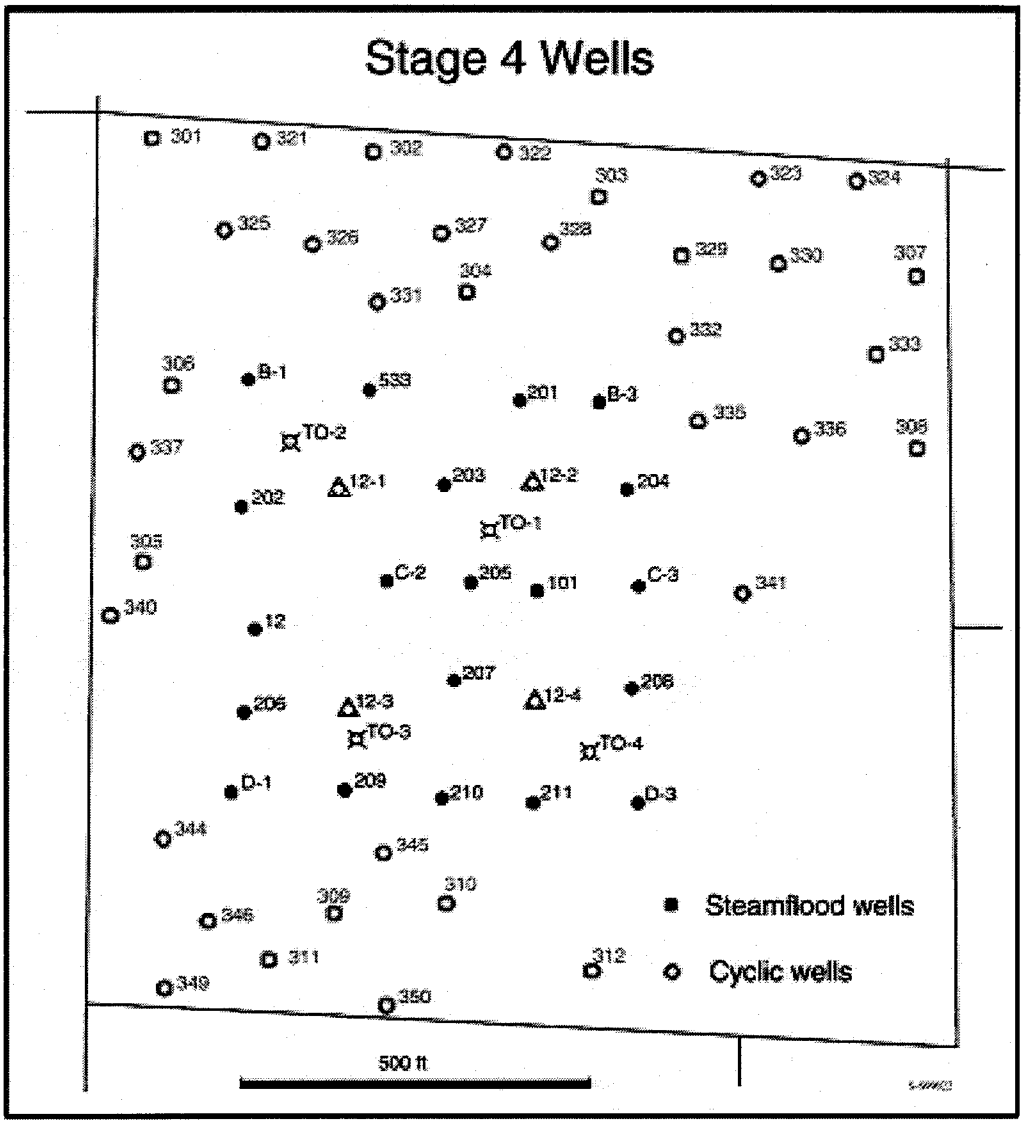

Figure 4-1: Location of new cyclic Pru 300-series producers drilled by AWE in 1998 (open circles). The preexisting 4-pattern steam flood pilot wells are shown in the center of the Pru Fee property as closed circles (producers) and triangles (injectors). The TO wells are for temperature observation only.

TABLE 4-1: WELLS DRILLED ON THE PRU FEE PROPERTY BY ARCO WESTERN ENERGY IN 1998

Well Name	API Serial No.	Spud Date	Prod. Month	TD (ft)	KB (ft)	GL (ft)	Logged?
Pru 301	04030-10130	1/12/98	Feb-98	1472	1470	1456	No
Pru 302	04030-10131	1/18/98	Feb-98	1422	1419	1405	No
Pur 303	04030-10132	1/21/98	Feb-98	1411	1419	1405	No
Pru 304	04030-10133	1/15/98	Feb-98	1429	1437	1423	No
Pru 305	04030-10134	1/5/98	Feb-98	1381	1408	1394	No
Pru 306	04030-10135	1/9/98	Feb-98	1443	1452	1438	No
Pru 307	04030-11501	5/20/98	Oct-98	1436	1400	1386	Yes
Pru 308	04030-11502	5/24/98	Jul-98	1408	1378	1364	Yes
Pru 309	04030-11503	5/14/98	Sep-98	1385	1415	1401	No
Pru 310	04030-11504	5/11/98	Jul-98	1430	1411	1397	Yes
Pru 311	04030-11505	5/17/98	Oct-98	1439	1416	1402	Yes
Pru 312	04030-11506	5/7/98	Jul-98	1496	1409	1395	Yes
Pru 320	04030-12395	9/24/98	Dec-98	1370	1406	1393	No
Pru 321	04030-12290	10/4/98	Feb-99	1400	1431	1418	No
Pru 322	04030-12291	8/28/98	Jan-99	1371	1418	1405	Yes
Pru 323	04030-12292	9/7/98	Oct-98	1383	1410	1397	Yes
Pru 324	04030-12293	9/9/98	Oct-98	1363	1409	1396	No
Pru 325	04030-12294	10/6/98	Jan-99	1420	1469	1456	No
Pru 326	04030-12295	9/13/98	Feb-99	1444	1431	1418	Yes
Pru 327	04030-12296	10/9/98	Jan-99	1395	1431	1418	No
Pru 328	04030-12297	9/27/98	Oct-98	1432	1417	1404	Yes
Pru 329	04030-12298	10/13/98	Nov-98	1353	1406	1393	No
Pru 330	04030-12299	10/16/98	Nov-98	1347	1406	1393	No
Pru 331	04030-12396	10/11/98	Nov-98	1395	1430	1417	No
Pru 332	04030-12397	10/19/98	Jan-99	1337	1393	1380	No
Pru 333	04030-12398	10/21/98	Jan-99	1318	1373	1363	No
Pru 334	04030-12399	10/2/98	Jan-99	1415	1451	1438	No
Pru 335	04030-12300	9/4/98	Oct-98	1341	1382	1369	Yes
Pru 336	04030-12301	9/2/98	Oct-98	1378	1380	1367	Yes
Pru 337	04030-12400	9/30/98	Jan-99	1433	1452	1439	No
Pru 340	04030-12401	9/22/98	Oct-98	1403	1417	1404	No
Pru 341	04030-12302	8/30/98	Oct-98	1364	1367	1354	Yes
Pru 344	04030-12402	9/19/98	Oct-98	1391	1431	1418	No
Pru 345	04030-12403	9/8/98	Oct-98	1379	1413	1400	No
Pru 346	04030-12404	9/15/98	Nov-98	1375	1418	1405	No
Pru 349	04030-12405	9/17/98	Oct-98	1388	1419	1406	No
Pru 350	04030-12406	9/10/98	Oct-98	1372	1413	1400	No

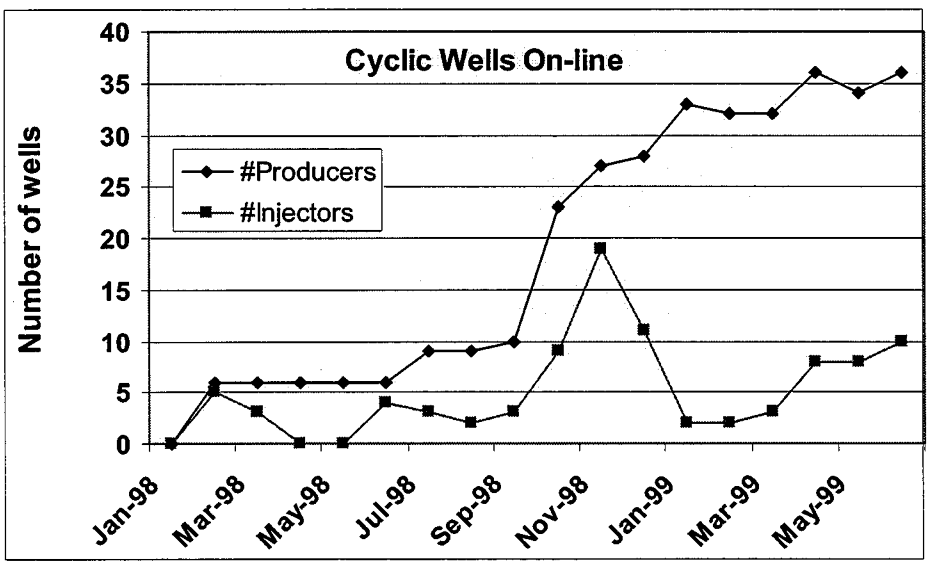

Figure 4-2: Number of "300-series" wells being steam cycled or produced in each month since January 1998.

Initial Production from Additional Cyclic Wells

The first six of the 37 "300-series" wells were drilled in January 1998. Within a month these wells were steamed and put into production. Since February 1998, this group of wells have been contributing to the total oil production from the Pru Fee property (Table 4-2). Production has increased progressively over the past year and a half with monthly oil rates closely following additional wells coming on line and substantial increases in steaming rates (Fig. 4-3). The peak oil rate of 458.5 BOPD reached in March 1999 relates directly with nearly all cyclic wells having been freshly steamed and put into production. In June, the oil rate had dropped back somewhat to 374.9 BOPD.

By the end of June 1999, the cummulative oil production from the "300-series" cyclic wells had reached 129.7 MBO. This brings the total cummulative production from all of the Pru Fee property by mid-year to 413.7 MBO.

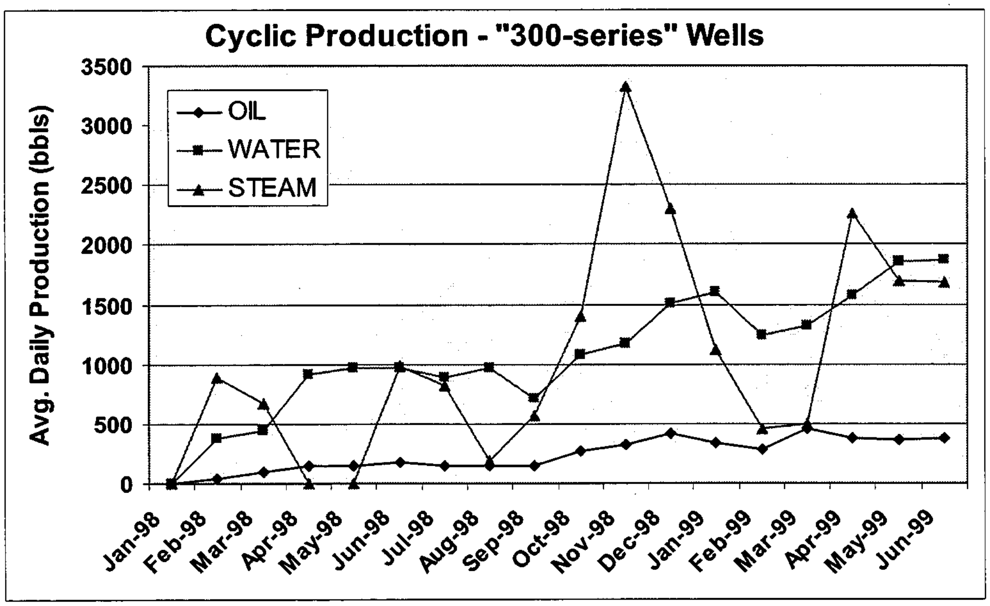

Figure 4-3: Production rates for the "300-series" wells produced by cyclic thermal recovery during the period February 1998 through June 1999. The three "spikes" in steam rates relate to the initial cycling of the wells drilled in January, May and August-October 1998, respectively.

Table 4-2: Monthly production in the Pru cyclic "300-series" wells February 1998-June 1999

	Average Daily Rate			*Total for the Month*		
Month	**BOPD** bbls	**BWPD** bbls	**BSPD** bbls	**Oil** bbls	**Water** bbls	**Steam** bbls
February	40.9	375.9	888.6	1,146	10,525	24,881
March	93.6	438.5	679.0	2,901	13,592	21,050
April	154.0	917.5	0.0	4,620	27,525	0
May	150.5	968.9	0.0	4,666	30,035	0
June	170.7	965.8	978.4	5,121	28,975	29,353
July	148.2	890.8	825.5	4,595	27,615	25,589
August	153.0	969.5	183.8	4,743	30,053	5,792
September	146.7	709.9	560.7	4,402	21,296	16,821
October	263.5	1,079.3	1,396.6	8,170	33,457	43,295
November	320.6	1,175.1	3,329.0	9,619	35,253	99,870
December	421.2	1,509.1	2,298.2	13,057	46,781	71.263
January	334.7	1,597.0	1,112.3	10,377	49,506	34,482
February	289.0	1,235.4	460.1	8,091	34,590	12,883
March	458.5	1,316.9	503.5	14,213	40,824	15,608
April	381.1	1,580.9	2,264.1	11,434	47,426	67,923
May	363.4	1,855.3	1,700.4	11,266	57,513	52,712
June	374.9	1,871.2	1,689.1	11,246	56,137	50,673

Chapter 5

Comparison of Production with Reservoir Model

Production from the Pru pilot in the initial two years of the steam flood was compared to the preliminary model predictions made at the onset of the demonstration. These three-dimensional simulations were performed using a 6 x 6 x 20 grid system. Development of the model and model results have been discussed in the 1996-97 and 1997-98 Annual Reports.

The pilot oil rate since the start of the flood is shown in Figure 5-1. The peak-rate is just over 400 barrels per day. In comparison, the model peak rates were about 480 barrels per day, but these were predicted to occur three years into the flood. Either the field oil rates are slightly lower than that predicted by the model or insufficient time has lapsed since the onset of the steam flood.

The pilot oil-steam ratio (OSR) is shown in Figure 5-2 and the model predictions for OSR are shown in Figure 5-3. The peak OSR values in the field are around 0.4, which are significantly higher than the model OSR values. Once again these peak OSR values are reached relatively early in the field compared to the model predictions. Cumulative OSR of 0.24 was realized in the pilot. The model predicts a cumulative OSR value of just 0.13 at this stage of the flood.

There may be several reasons for these early trends in the field:

1. The flood is being conducted higher in the reservoir than in the model. Thus, the steam is contacting a reservoir of significantly higher oil saturation.

2. The oil saturations, which are essentially projected using the log-core relations from the Pru-101 well may be too pessimistic.

3. The reservoir may have been heated significantly during earlier thermal production and that heating not recorded or the reservoir is heated by nearby steaming activity in adjacent properties, neither heating having been adequately accounted for in the model.

If the higher OSR values currently seen in the field are the result only of sweeping just the upper reservoir, these trends will continue. Without intervention to correct this situation by lowering the sweep, the overall recovery over a 10-20 year production period will be significantly lower than predicted from the model.

Another way of examining the field performance is to compare the injection-production record. Figure 5-4 shows the cumulative oil production in the field as a function of steam injected. The model equivalent of this curve is shown in Figure 5-5. The model is for a half-acre symmetry element of the inverted nine-spot pattern. Thus, the injection and production numbers need to multiplied by a factor of 16 for the total numbers to be equivalent to the field values for the 8 ac pilot. It is seen that the model predicts oil production of only about 6,500 barrels of oil produced for every 50,000 barrels of steam injected (for the half-acre symmetry element). Over the entire pilot, this corresponds to an oil production of 104,000 barrels of oil produced for 800,000 barrels of steam injected. However, the field results as of October 1998 indicate that over 192,000 barrels of oil were produced for 808,000 barrels of steam injected. Thus, the field appears to be outperforming the model predictions at this stage.

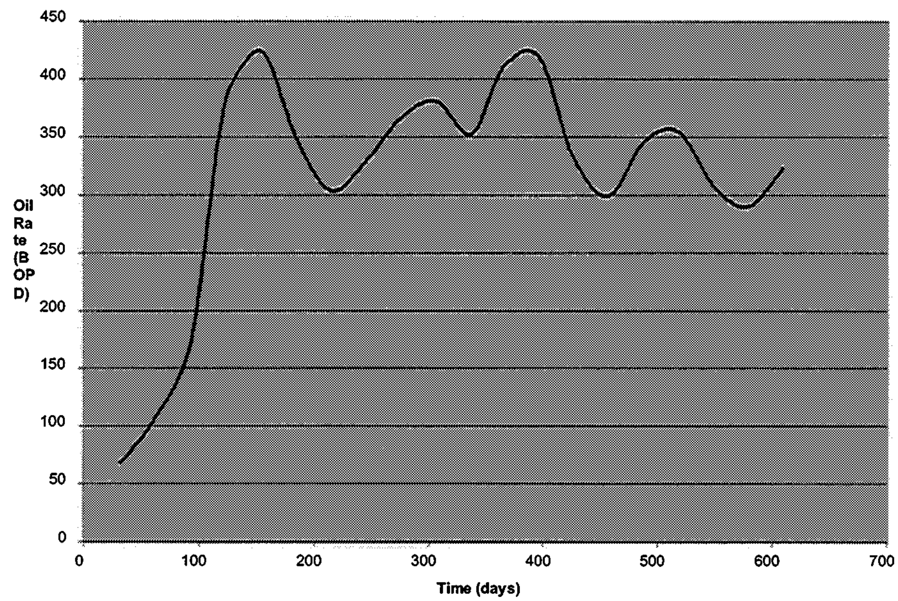

Figure 5-1: Oil rate in the field.

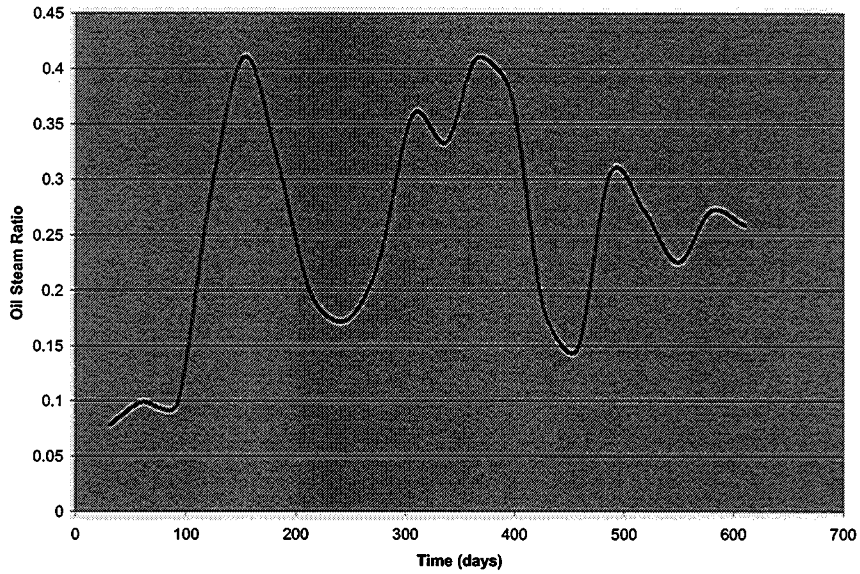

Figure 5-2: Oil steam ratio observed in the field.

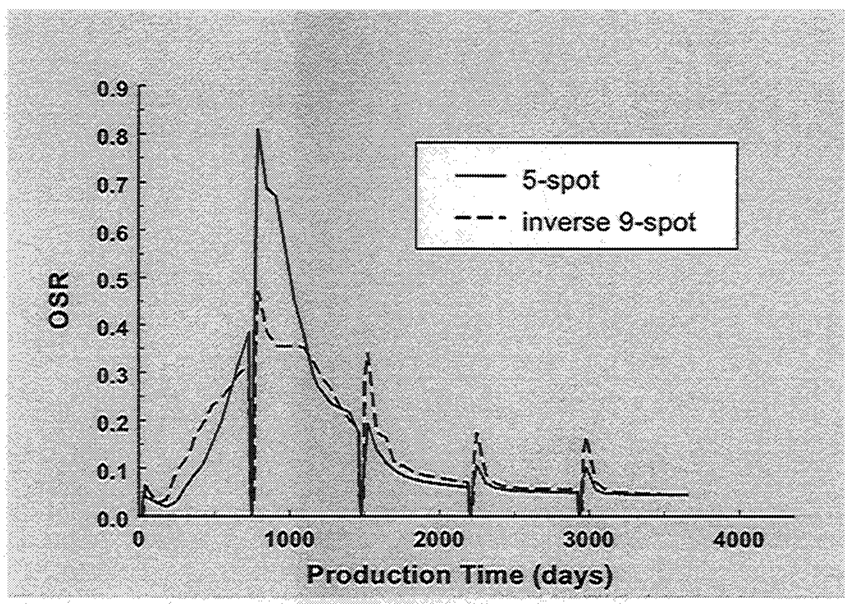

Figure 5-3: Oil steam ratio predicted by the model.

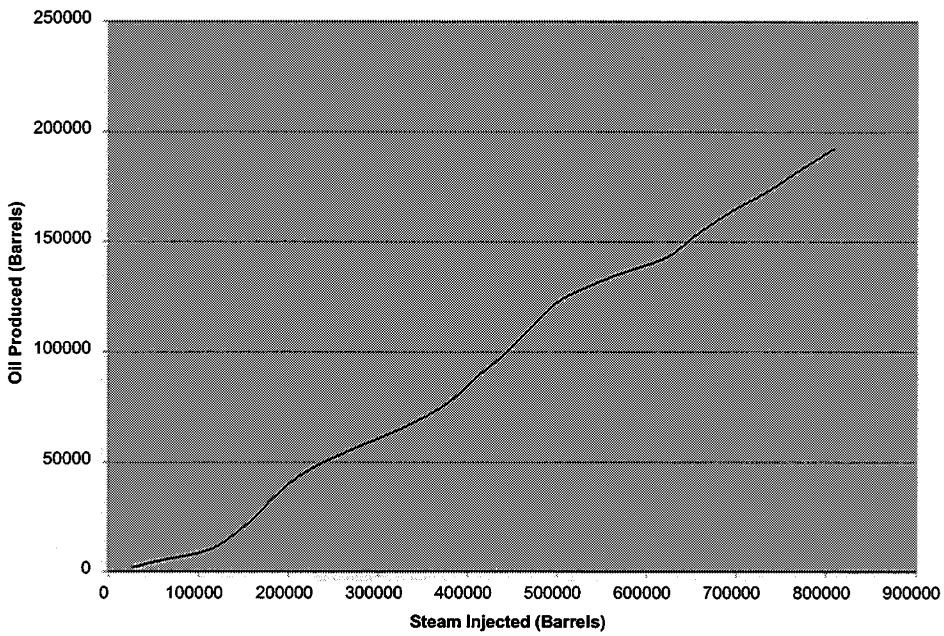

Figure 5-4: Cumulative oil produced in the field as a function of steam injected.

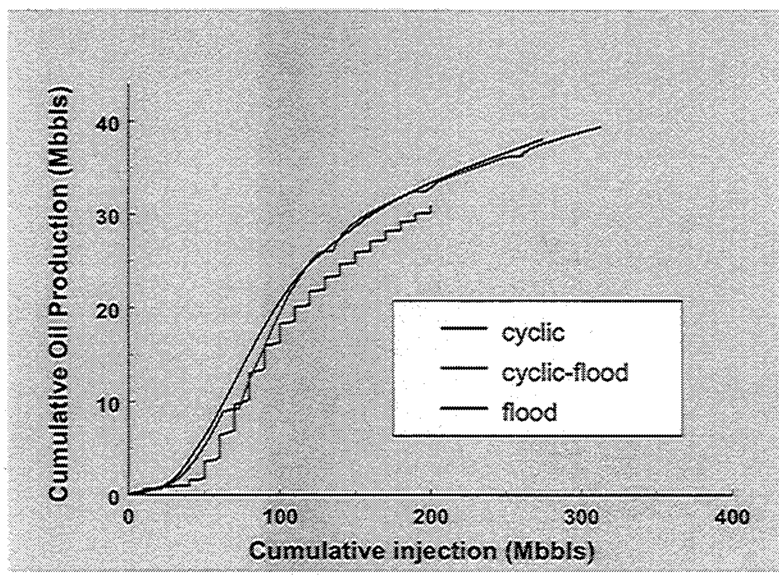

Figure 5-5: Cumulative oil produced as predicted by the model as a function of steam injected.

Chapter 6

Vertical Variations in Oil Saturation

Heavy oil production at the Pru pilot is from the upper Miocene Monarch Sand, part of the Belridge Diatomite Member of the Monterey Formation. The pay interval is just 1100-1400 ft deep. Like other sand bodies within the Monterey Formation, it is a deep submarine channel or proximal fan deposit encased in diatomaceous mudstone. The sand is derived from an elevated portion of the Salinas block, which during the late Miocene lay immediately to the west of the San Andreas fault just 15 miles to the west of the site. The top of the Monarch Sand, actually a Pliocene/Miocene unconformity, dips at less than 10° to the southwest. The unconformity bevels downward at a very low angle to the northwest across the upper portion of the Monarch Sand body. The net pay zone, which averages 220 ft at Pru, thins to the southeast as the top of the sand dips through the nearly horizontal oil-water contact (OWC). In the southeast half of the Pru property a thin wedge of Belridge Diatomite overlies the Monarch Sand beneath the Pliocene/Miocene unconformity providing a somewhat more effective steam barrier than the Pliocene Etchegoin Formation, a silty, sandy mudstone.

The only other oil-bearing unit at the Pru Fee property is the Tulare Formation, interbedded fluvial sands and shales at a depth of about 500 ft that contain an estimated 2.5 MMBO potential reserves. These additional reserves were discovered as a consequence of drilling and logging the wells for the DOE Class 3 project. Production by cyclic steaming of heavy oil from the Tulare was started in the second half of 1998 in the southern third of the Pru property.

Average Monarch Sand reservoir characteristics derived from core and the log model developed for this project are 31% porosity and 2250 md permeability. The "initial" (1995) average oil saturation is estimated to be 59%. However, all wells have a relatively thick transition zone of downward decreasing oil saturation in the bottom half of the pay interval. The oil is both heavy and viscous, about 13° API and 2200 cp at the initial (1995) reservoir temperature of 100° F.

The vertical variation in oil saturation, represented as water saturation (**Sw**), is depicted for the steam flood pilot in a set of four cross sections. The location of the sections is shown in Figure. In the sections (Figs. 6-2 through 6-5), the top of the Monarch Sand is indicated by the surfaces BEF and BUM. An intermediate diatomite-rich interval within the Monarch Sand is bounded by the surfaces TMB and BMB. The bottom of the pay interval is the oil-water contact, OWC.

For each well a porosity log is on the right, showing gross variations in lithology, and a pair of calculated **Sw** logs is on the left. **Sw** is depicted with a standard Archie curve and a modified Archie curve based on petrophysical analysis of the Pru 101 core by ARCO

Exploration & Production Research. The reader is referred to the 1995-96 Annual Report for a full discussion of this modified Archie equation. The modified Archie equation results in about 5% higher oil saturations (**So**) than the standard Archie equation. In the set of cross sections the modified Archie curve stands slightly to the left of the standard Archie curve, that is, at lower values of **Sw** and higher values of **So**. The vertical and lateral variations in **So** are seen in the degree to which the paired curves swing upward to the left. A 50% cutoff has been added to the two **Sw** curves to make them easier to read.

The cross sections show that in general the **So** values in the upper third to upper half of the pay interval exceed 50%. The highest values of **So** are in the upper third of the interval. However, virtually all wells show **So** decreasing substantially in a "oil depletion" zone 10-30 ft thick at the very top of the Monarch Sand reservoir. The oil depletion zone is thought to be the product of earlier (pre-1995) thermal production and downward drainage of oil in the reservoir.

Reservoir simulations with geostatistically generated data sets reveals that the initial fluid distribution in the reservoir has the most significant impact on the economics of the cyclic-flooding process. The initial fluid distribution is determined by the placement of the OWC and the resulting **So** transition zone in the reservoir. The current approach to production involves initial steam injection within the upper third of the oil column, where **So** generally is greater than 60%, so as to avoid undue loss of heat to water.

The thermal cross sections (Figs. 6-6 and 6-7) are showing an effective steam sweep through the uppermost (and most oil-rich) portion of the Monarch Sand reservoir. However, steam is beginning to move up into the overlying Etchegoin Formation reducing sweep efficiency. The injection intervals, which in retrospect were placed too high, should be moved downward about 40 feet to address this problem, especially in the two northern injector wells.

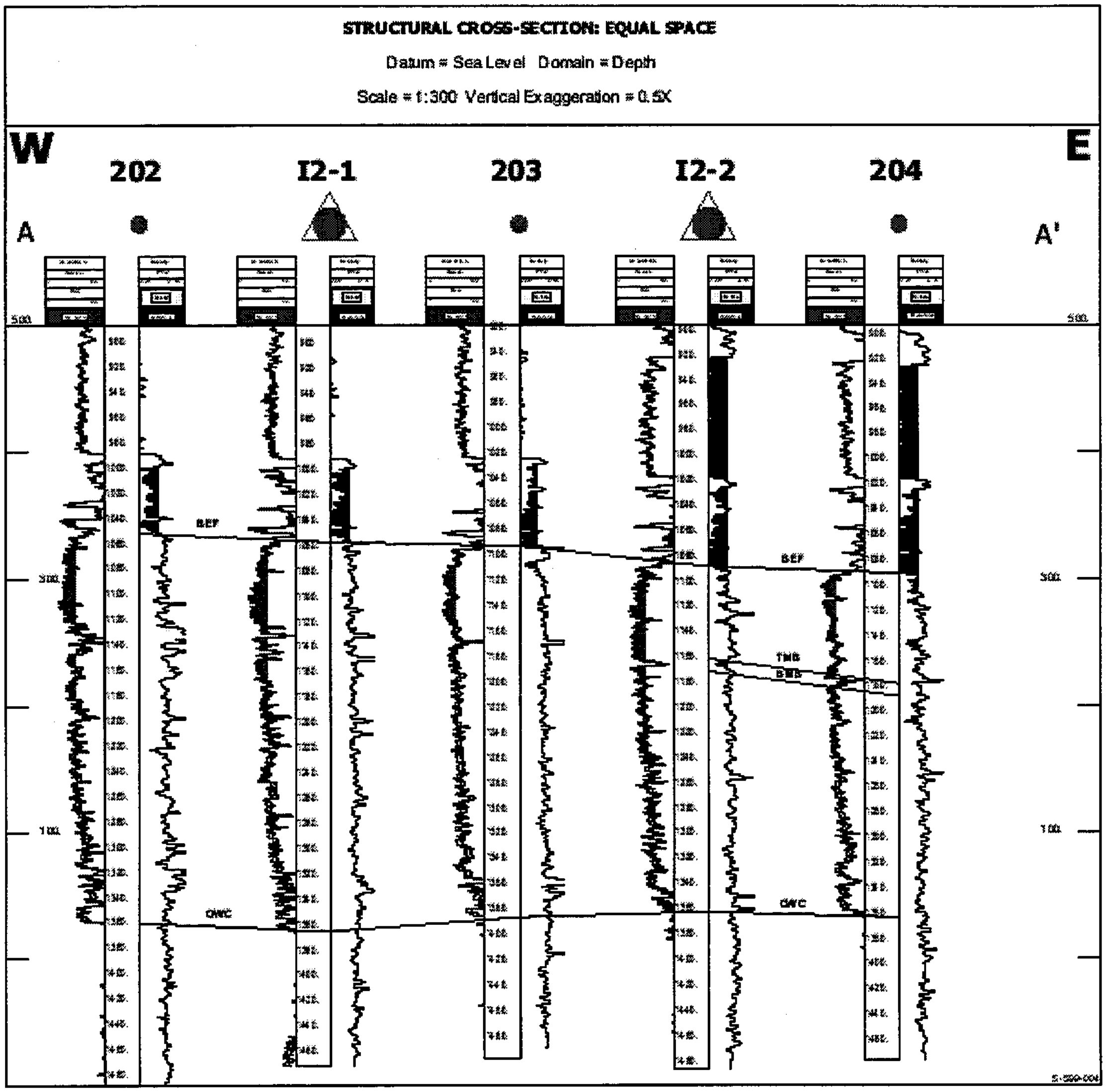

*Figure 6-2: Water saturation (**Sw**) and porosity logs for a set of wells in a west-east cross section through the northern portion of the Pru steam flood pilot. Note the gradual decrease in **Sw** (increase in **So**) upward through the oil-saturated interval above the OWC.*

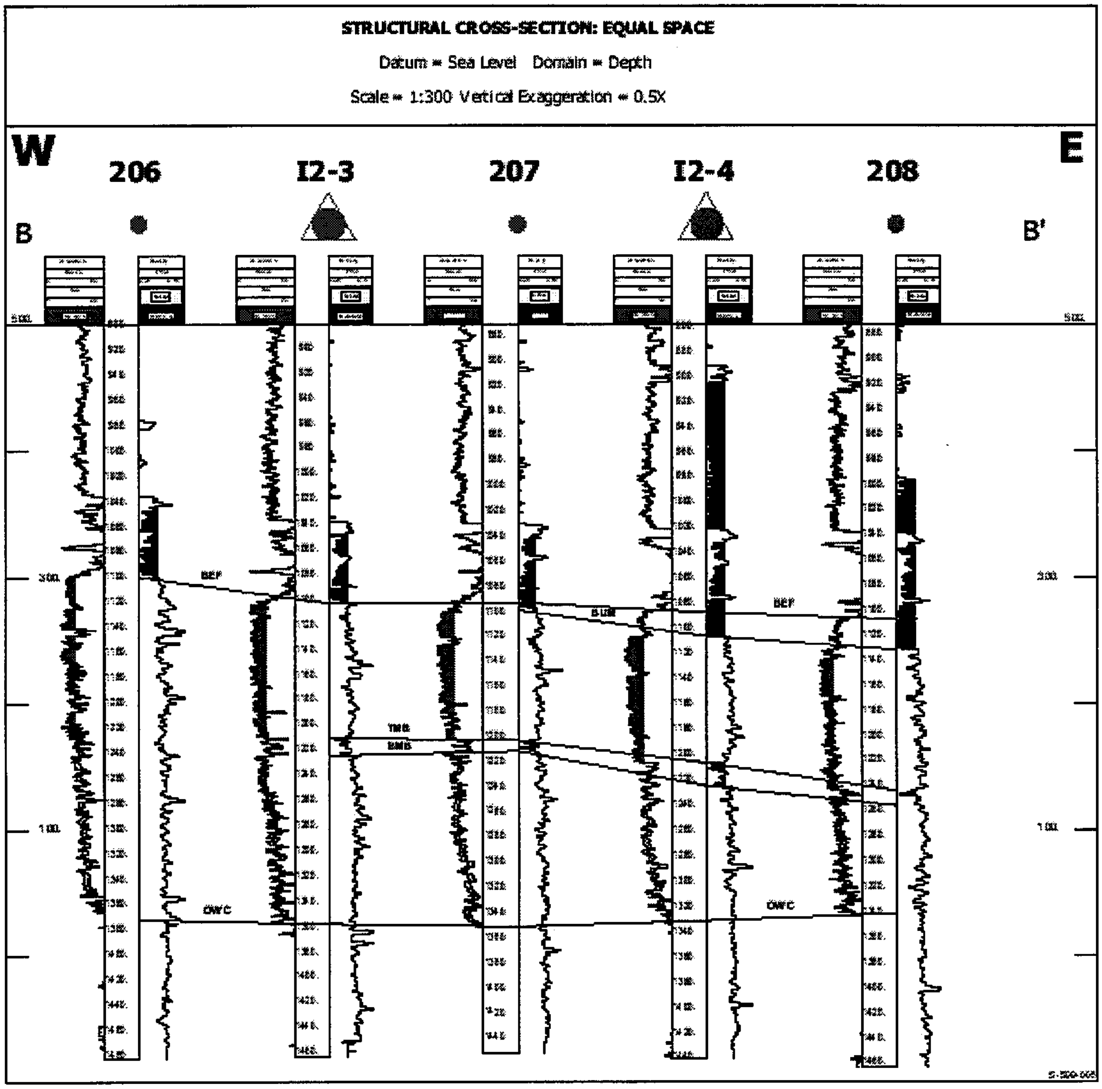

*Figure 6-3: Water saturation (**Sw**) and porosity logs for a set of wells in a west-east cross section through the southern portion of the Pru steam flood pilot. Note the gradual decrease in **Sw** (increase in **So**) upward through the oil-saturated interval above the OWC.*

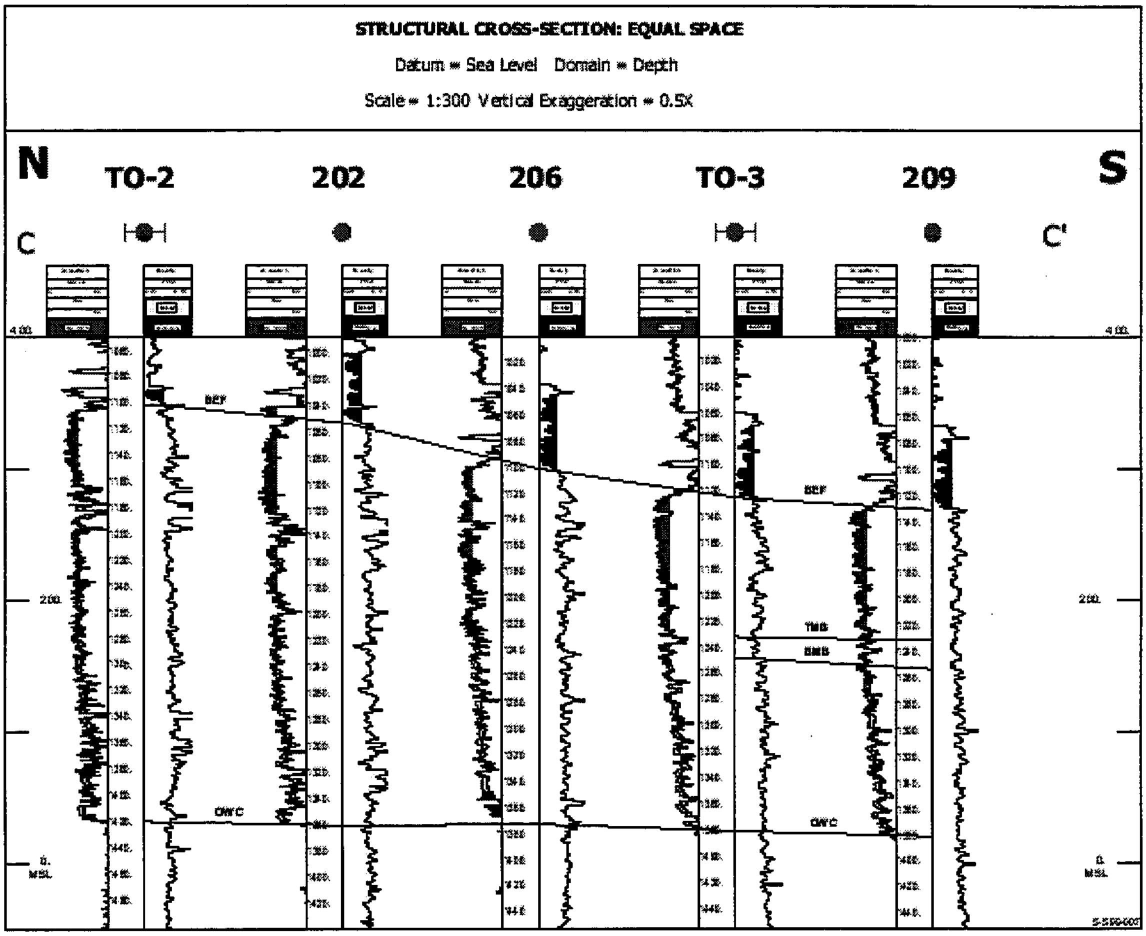

*Figure 6-4: Water saturation (**Sw**) and porosity logs for a set of wells in a north-south cross section through the western portion of the Pru steam flood pilot. Note the gradual decrease in **Sw** (increase in **So**) upward through the oil-saturated interval above the OWC.*

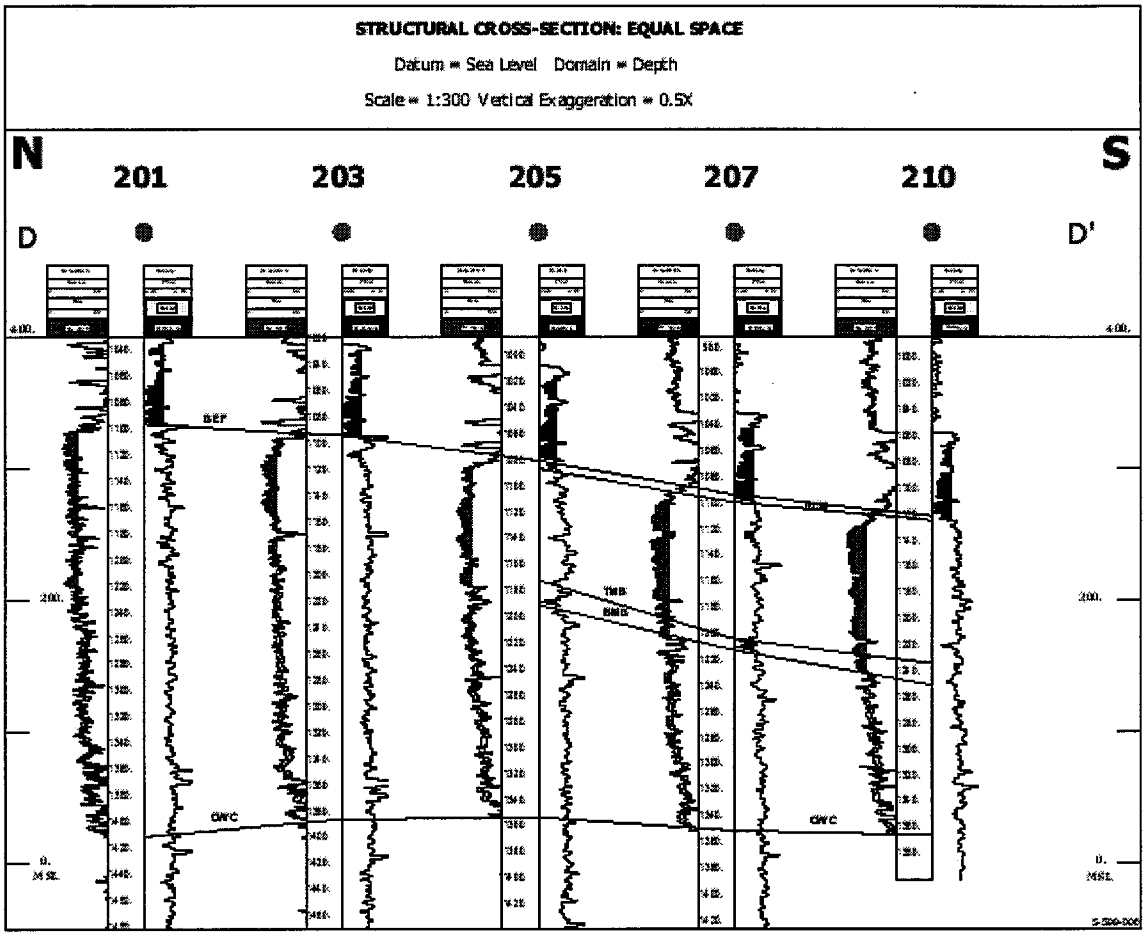

*Figure 6-5: Water saturation (**Sw**) and porosity logs for a set of wells in a north-south cross section through the eastern portion of the Pru steam flood pilot. Note the gradual decrease in **Sw** (increase in **So**) upward through the oil-saturated interval above the OWC.*

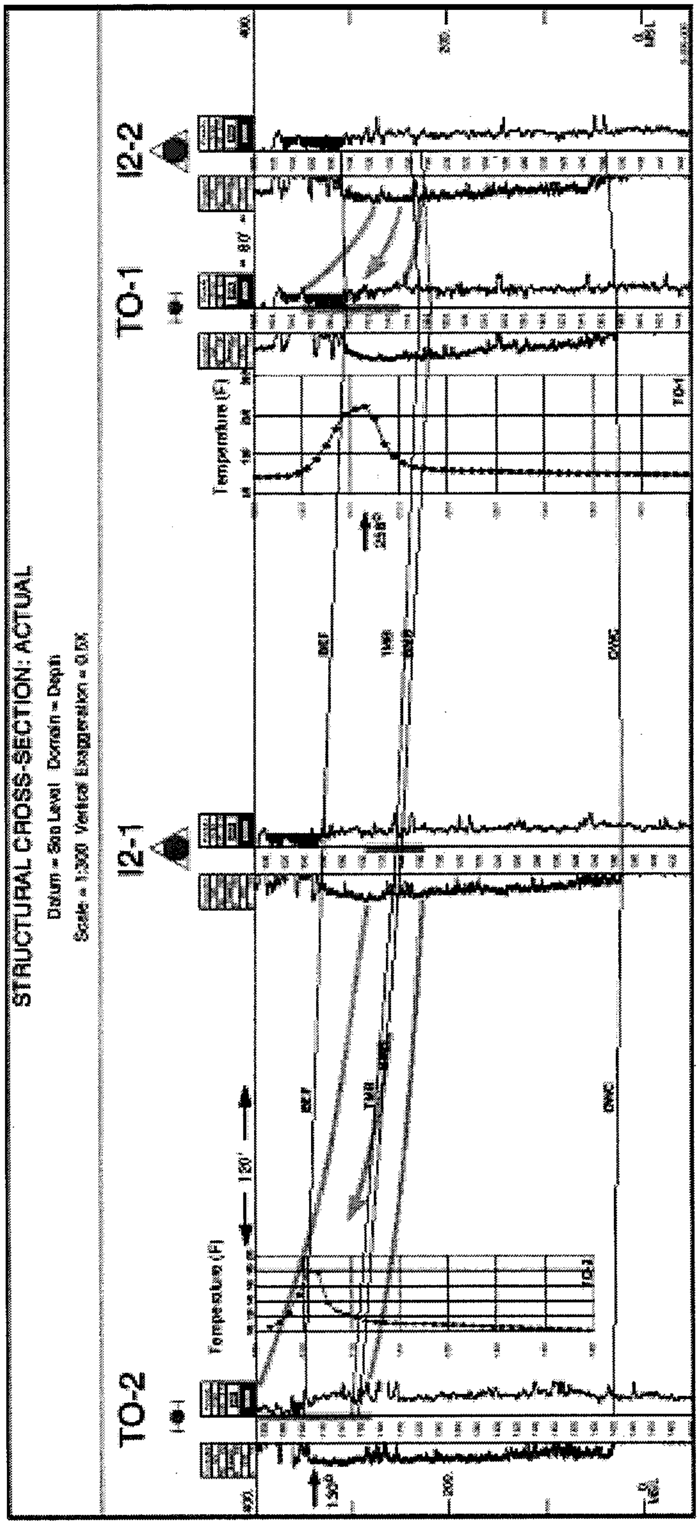

Figure 6-6: Cross section showing the steam sweep from the I2-1 and I2-2 injectors to the thermal observation wells TO-2 and TO-1 in the northern half of the Pru steam flood pilot. The temperature logs are for November 1998.

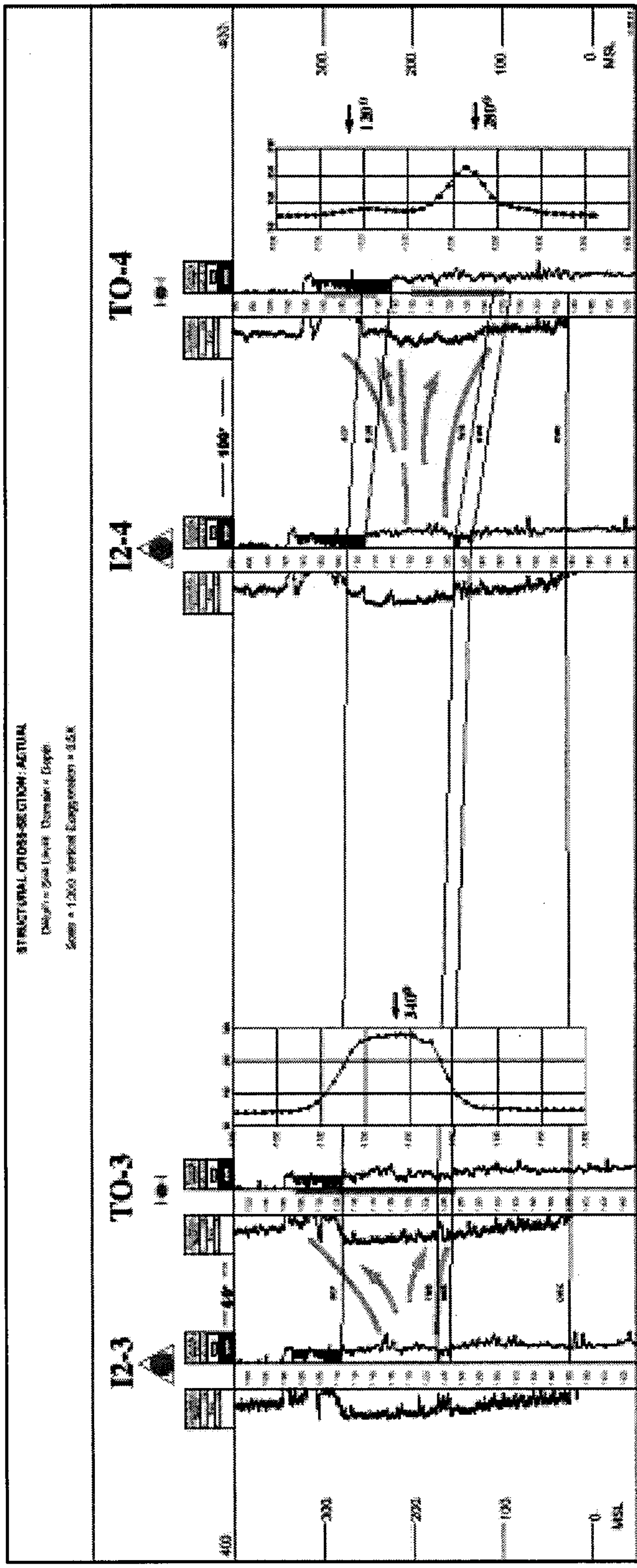

Figure 6-7: Cross section showing the steam sweep from the I2-3 and I2-4 injectors to the temperature observation wells TO-3 and TO-4 in the southern half of the Pru steam flood poilot. The temperature logs are from November 1998.

The 37 new wells drilled on the Pru Fee property flanking the existing 8 ac four-pattern steam flood pilot near the center of the property provide an opportunity to enlarge our understanding of the distribution of oil saturation. Within the steam flood pilot wells, it was observed that oil saturations increased in a very regular pattern upward from the oil-water contact (OWC). In the interval immediately above the OWC the oil saturations were about 20%, a value thought to represent the irreducible oil saturation in this highly porous and permeable Monarch Sand reservoir. The oil saturations increase very gradually upward over an interval of 150 to 200 ft, finally reaching a maximum value in the range 60-70% through an interval approximately 100 ft thick near the top of the sand body. The production strategy adopted in the steam flood pilot is to restrict steam injection to the upper one-third of the pay zone, that portion where oil saturations exceed 50%. Any steam injected below this interval would loose large quantities of heat to water and result in unfavorable steam-oil and water-oil ratios.

Twelve of the new "300-series" wells were logged using the same tools as the wells drilled for the steam flood pilot. This permits use of the same formulas for calculation of water (oil) saturations and comparison between the two sets of wells.

Two stratigraphic cross sections have been prepared showing the water (oil) saturation and rock porosity log profiles for seven of the "300-series" wells. The cross section in Figure 6-8 is oriented west-east traversing the northern third of the Pru Fee property. The other cross section (Fig. 6-9) trends north-south in the northeastern quadrant of the property. In most of the log profiles a gradual upward increase in oil saturation is observed.

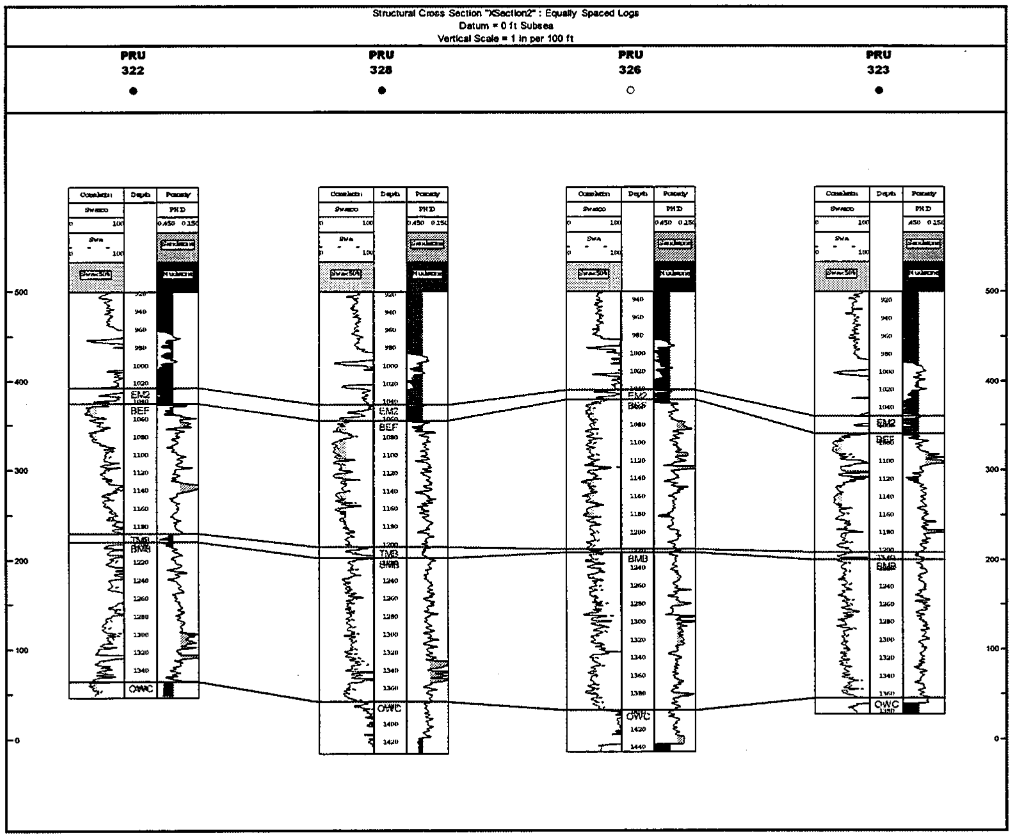

Figure 6-8: West-east stratigraphic cross section through the Monarch Sand reservoir and overlying shaly Echegoin Formation in the northern third of the Pru Fee property showing water (oil) saturation(left channel) and rock porosity (right channel) curves. The wells are Pru-322, Pru-328, Pru-326 and Pru-323.

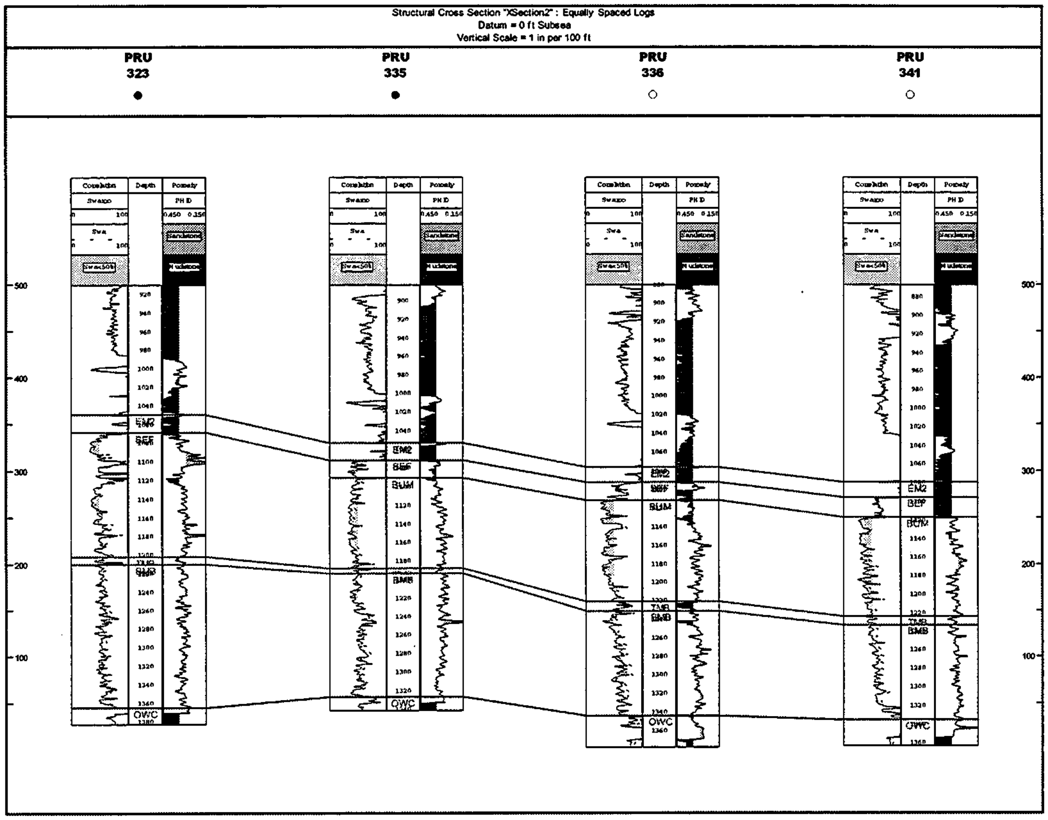

Figure 6-9: North-south stratigraphic cross section through the Monarch Sand reservoir and overlying shaly Echegoin Formation in the northeastern quadrant of the Pru Fee property showing water (oil) saturation and rock porosity curves. The wells are Pru-323, Pru-335, Pru-336 and Pru-341.

Chapter 7

Technology Transfer

In the fourth year of the project no substantially new information or concepts were generated. The project had entered into a phase of data collection on production response in steam flood and in cyclic mode. As a consequence, there were few opportunities for presenting papers and developing new publications.

Nevertheless, during the second quarter of 1999 two technical papers related directly to the project were presented at professional meetings:

- **1999 SPE International Thermal Operations and Heavy Oil Symposium**
  Bakersfield, CA March 17-19

Strategies for steam flood optimization in a high-water saturation reservoir in the Midway-Sunset field by M. D. Deo, C. Forster and S. Schamel

- **1999 AAPG Annual Convention (San Antonio, TX) – April 11-14, 1999**
  AAPG Session: Exploration and Development in Mature Basins and Old Fields

Strategies for steam flood optimization in the Midway-Sunset field, southern San Joaquin Basin, California. by S. Schamel, M. Deo, C. Forster, D. Sprinkel, and K. Olsen.